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64 S.Ct. 281
Supreme Court of the United States

FEDERAL POWER COMMISSION et al.
v.
HOPE NATURAL GAS CO.
CITY OF CLEVELAND
v.
SAME.

Nos. 34 and 35. | Argued Oct. 20, 21, 1943. | Decided Jan. 3, 1944.

Separate proceedings before the Federal Power Commission by such Commission, by the City of Cleveland and the City of Akron, and by Pennsylvania Public Utility Commission wherein the State of West Virginia and its Public Service Commission were permitted to intervene concerning rates charged by Hope Natural Gas Company which were consolidated for hearing. An order fixing rates was reversed and remanded with directions by the Circuit Court of Appeals, 134 F.2d 287, and Federal Power Commission, City of Akron and Pennsylvania Public Utility Commission in one case and the City of Cleveland in another bring certiorari.

Reversed.

Mr. Justice REED, Mr. Justice FRANKFURTER and Mr. Justice JACKSON, dissenting.

On Writs of Certiorari to the United States Circuit Court of Appeals for the Fourth Circuit.

West Headnotes (26)

[1] **Public Utilities**
Nature and extent in general

Rate-making is only one species of price-fixing which, like other applications of the police power, may reduce the value of the property regulated, but that does not render the regulation invalid.

25 Cases that cite this headnote

[2] **Public Utilities**
Reasonableness of charges in general

Rates cannot be made to depend upon fair value, which is the end product of the process of rate-making and not the starting point, when the value of the going enterprise depends on earnings under whatever rates may be anticipated.

101 Cases that cite this headnote

[3] **Gas**
Federal Power Commission

The rate-making function of the Federal Power Commission under the Natural Gas Act involves the making of pragmatic adjustments, and the Commission is not bound to the use of any single formula or combination of formulae in determining rates. Natural Gas Act, §§ 4(a), 5(a), 6, 15 U.S.C.A. §§ 717c(a), 717d(a), 717e.

46 Cases that cite this headnote

[4] **Gas**
Scope of review and trial de novo

When order of Federal Power Commission fixing natural gas rates is challenged in the courts, the question is whether order viewed in its entirety meets the requirements of the Natural Gas Act. Natural Gas Act, §§ 4(a), 5(a), 6, 19(b), 15 U.S.C.A. §§ 717c(a), 717d(a), 717e, 717r(b).

8 Cases that cite this headnote

[5] **Gas**
Reasonableness of Charges

Under the statutory standard that natural gas rates shall be "just and reasonable" it is the result reached and not the method employed that is controlling. Natural Gas Act §§ 4(a), 5(a), 15 U.S.C.A. §§ 717c(a), 717d(a).

69 Cases that cite this headnote

[6] **Gas**
Scope of review and trial de novo

If the total effect of natural gas rates fixed by Federal Power Commission cannot be said to be unjust and unreasonable, judicial inquiry under the Natural Gas Act is at an end. Natural Gas Act, §§ 4(a), 5(a), 6, 19(b), 15 U.S.C.A. §§ 717c(a), 717d(a), 717e, 717r(b).

74 Cases that cite this headnote

[7] Gas

Presumptions

An order of the Federal Power Commission fixing rates for natural gas is the product of expert judgment, which carries a presumption of validity, and one who would upset the rate must make a convincing showing that it is invalid because it is unjust and unreasonable in its consequences. Natural Gas Act, §§ 4(a), 5(a), 6, 19(b), 15 U.S.C.A. §§ 717c(a), 717d(a), 717e, 717r(b).

118 Cases that cite this headnote

[8] Gas

Reasonableness of Charges

The fixing of just and reasonable rates for natural gas by the Federal Power Commission involves a balancing of the investor and the consumer interests. Natural Gas Act, §§ 4(a), 5(a), 15 U.S.C.A. §§ 717c(a), 717d(a).

52 Cases that cite this headnote

[9] Gas

Depreciation and depletion

As respects rates for natural gas, from the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business, which includes service on the debt and dividends on stock, and by such standard the return to the equity owner should be commensurate with the terms on investments in other enterprises having corresponding risks, and such returns should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and to attract capital. Natural Gas Act, §§ 4(a), 5(a), 15 U.S.C.A. §§ 717c(a), 717d(a).

265 Cases that cite this headnote

[10] Gas

Depreciation and depletion

The fixing by the Federal Power Commission of a rate of return that permitted a natural gas company to earn $2,191,314 annually was supported by substantial evidence. Natural Gas Act, §§ 4(a), 5(a), 6, 19(b), 15 U.S.C.A. §§ 717c(a), 717d(a), 717e, 717r(b).

3 Cases that cite this headnote

[11] Gas

Depreciation and depletion

Rates which enable a natural gas company to operate successfully, to maintain its financial integrity, to attract capital and to compensate its investors for the risks assumed cannot be condemned as invalid, even though they might produce only a meager return on the so-called "fair value" rate base. Natural Gas Act, §§ 4(a), 5(a), 6, 19(b), 15 U.S.C.A. §§ 717c(a), 717d(a), 717e, 717r(b).

155 Cases that cite this headnote

[12] Gas

Method of valuation

A return of only 3 27/100 per cent. on alleged rate base computed on reproduction cost new to natural gas company earning an annual average return of about 9 per cent. on average investment and satisfied with existing gas rates suggests an inflation of the base on which the rate had been computed, and justified Federal Power Commission in rejecting reproduction cost as the measure of the rate base. Natural Gas Act, §§ 4(a), 5(a), 15 U.S.C.A. §§ 717c(a), 717d(a).

64 Cases that cite this headnote

[13] Gas

Depreciation and depletion

There is no constitutional requirement that owner who engages in a wasting-asset business of limited life shall receive at the end more than he has put into it, and such rule is applicable to a natural gas company since the ultimate exhaustion of its supply of gas is inevitable. Natural Gas Act, §§ 4(a), 5(a), 6, 19(b), 15 U.S.C.A. §§ 717c(a), 717d(a), 717e, 717r(b).

1 Cases that cite this headnote

[14] **Gas**
Depreciation and depletion

In fixing natural gas rate the basing of annual depreciation on cost is proper since by such procedure the utility is made whole and the integrity of its investment is maintained, and no more is required. Natural Gas Act, §§ 4(a), 5(a), 6, 19(b), 15 U.S.C.A. §§ 717c(a), 717d(a), 717e, 717r(b).

13 Cases that cite this headnote

[15] **Gas**
Findings and orders

There are no constitutional requirements more exacting than the standards of the Natural Gas Act which are that gas rates shall be just and reasonable, and a rate order which conforms with the act is valid. Natural Gas Act, §§ 4(a), 5(a), 6, 19(b), 15 U.S.C.A. §§ 717c(a), 717d(a), 717e, 717r(b).

13 Cases that cite this headnote

[16] **Commerce**
Gas

The purpose of the Natural Gas Act was to provide through the exercise of the national power over interstate commerce an agency for regulating the wholesale distribution to public service companies of natural gas moving in interstate commerce not subject to certain types of state regulation, and the act was not intended to take any authority from state commissions or to usurp state regulatory authority. Natural Gas Act, § 1 et seq., 15 U.S.C.A. § 717 et seq.

25 Cases that cite this headnote

[17] **Mines and Minerals**
Oil and gas

Under the Natural Gas Act, the Federal Power Commission has no authority over the production or gathering of natural gas. Natural Gas Act, § 1(b), 15 U.S.C.A. § 717(b).

8 Cases that cite this headnote

[18] **Gas**
In general; amount and regulation

The primary aim of the Natural Gas Act was to protect consumers against exploitation at the hands of natural gas companies and holding companies owning a majority of the pipeline mileage which moved gas in interstate commerce and against which state commissions, independent producers and communities were growing quite helpless. Natural Gas Act, §§ 4, 6–10, 14, 15 U.S.C.A. §§ 717c, 717e–717i, 717m.

59 Cases that cite this headnote

[19] **Gas**
In general; amount and regulation

Apart from the express exemptions contained in § 7 of the Natural Gas Act considerations of conservation are material where abandonment or extensions of facilities or service by natural gas companies are involved, but exploitation of consumers by private operators through maintenance of high rates cannot be continued because of the indirect benefits derived therefrom by a state containing natural gas deposits. Natural Gas Act, §§ 4, 5, and § 7 as amended 15 U.S.C.A. §§ 717c, 717d, 717f.

19 Cases that cite this headnote

[20] **Commerce**
Gas

A limitation on the net earnings of a natural gas company from its interstate business is not a limitation on the power of the producing state, either to safeguard its tax revenues from such industry, or to protect the interests of those who sell their gas to the interstate operator, particularly where the return allowed the company by the Federal Power Commission was a net return after all such charges. Natural

Gas Act, §§ 4, 5, and § 7, as amended, 15 U.S.C.A. §§ 717c, 717d, 717f.

10 Cases that cite this headnote

[21] **Gas**

Reasonableness of Charges

The Natural Gas Act granting Federal Power Commission power to fix "just and reasonable rates" does not include the power to fix rates which will disallow or discourage resales for industrial use. Natural Gas Act, §§ 4(a), 5(a), 15 U.S.C.A. §§ 717c(a), 717d(a).

73 Cases that cite this headnote

[22] **Gas**

Reasonableness of Charges

The wasting-asset nature of the natural gas industry does not require the maintenance of the level of rates so that natural gas companies can make a greater profit on each unit of gas sold. Natural Gas Act, §§ 4(a), 5(a), 15 U.S.C.A. §§ 717c(a), 717d(a).

1 Cases that cite this headnote

[23] **Federal Courts**

Presentation of Questions Below or on Review; Record; Waiver

Federal Courts

Scope and Extent of Review

Where the Federal Power Commission made no findings as to any discrimination or unreasonable differences in rates, and its failure was not challenged in the petition to review, and had not been raised or argued by any party, the problem of discrimination was not open to review by the Supreme Court on certiorari. Natural Gas Act, § 4(b), 15 U.S.C.A. § 717c(b).

18 Cases that cite this headnote

[24] **Constitutional Law**

Judicial encroachment on executive acts taken under statutory authority

Gas

Power to control and regulate

Congress has entrusted the administration of the Natural Gas Act to the Federal Power Commission and not to the courts, and apart from the requirements of judicial review, it is not for the Supreme Court to advise the Commission how to discharge its functions. Natural Gas Act, §§ 1 et seq., 19(b), 15 U.S.C.A. §§ 717 et seq., 717r(b).

13 Cases that cite this headnote

[25] **Gas**

Decisions reviewable

Under the Natural Gas Act, where order sought to be reviewed does not of itself adversely affect complainant but only affects his rights adversely on the contingency of future administrative action, the order is not reviewable, and resort to the courts in such situation is either premature or wholly beyond the province of such courts. Natural Gas Act, § 19(b), 15 U.S.C.A. § 717r(b).

8 Cases that cite this headnote

[26] **Gas**

Persons entitled to relief; parties

Findings of the Federal Power Commission on lawfulness of past natural gas rates, which the Commission was without power to enforce, were not reviewable under the Natural Gas Act giving any "party aggrieved" by an order of the Commission the right of review. Natural Gas Act, § 19(b), 15 U.S.C.A. § 717r(b).

27 Cases that cite this headnote

Attorneys and Law Firms

****283** ***592** Mr. Francis M. Shea, Asst. Atty. Gen., for petitioners Federal Power Com'n and others.

***593** Mr. Spencer W. Reeder, of Cleveland, Ohio, for petitioner City of cleveland.

Mr. William B. Cockley, of Cleveland, Ohio, for respondent.

Mr. M. M. Neeley, of Charleston, W. Va., for State of West Virginia, as amicus curiae by special leave of Court.

Opinion

Mr. Justice DOUGLAS delivered the opinion of the Court.

The primary issue in these cases concerns the validity under the Natural Gas Act of 1938, 52 Stat. 821, 15 U.S.C. s 717 et seq., 15 U.S.C.A. s 717 et seq., of a rate order issued by the Federal Power Commission reducing the rates chargeable by Hope Natural Gas Co., 44 P.U.R.,N.S., 1. On a petition for review of the order made pursuant to s 19(b) of the Act, the ***594** Circuit Court of Appeals set it aside, one judge dissenting. 4 Cir., 134 F.2d 287. The cases ****284** are here on petitions for writs of certiorari which we granted because of the public importance of the questions presented. City of Cleveland v. Hope Natural Gas Co., 319 U.S. 735, 63 S.Ct. 1165.

Hope is a West Virginia corporation organized in 1898. It is a wholly owned subsidiary of Standard Oil Co. (N.J.). Since the date of its organization, it has been in the business of producing, purchasing and marketing natural gas in that state. [1] It sells some of that gas to local consumers in West Virginia. But the great bulk of it goes to five customer companies which receive it at the West Virginia line and distribute it in Ohio and in Pennsylvania. [2] In July, 1938, the cities of Cleveland and Akron filed complaints with the Commission charging that the rates collected by Hope from East Ohio Gas Co. (an affiliate of Hope which distributes gas in Ohio) were excessive and unreasonable. Later in 1938 the Commission on its own motion instituted an investigation to determine the reasonableness of all of Hope's interstate rates. In March ***595** 1939 the Public Utility Commission of Pennsylvania filed a complaint with the Commission charging that the rates collected by Hope from Peoples Natural Gas Co. (an affiliate of Hope distributing gas in Pennsylvania) and two non-affiliated companies were unreasonable. The City of Cleveland asked that the challenged rates be declared unlawful and that just and reasonable rates be determined from June 30, 1939 to the date of the Commission's order. The latter finding was requested in aid of state regulation and to afford the Public Utilities Commission of Ohio a proper basic for disposition of a fund collected by East Ohio under bond from Ohio consumers since June 30, 1939. The cases were consolidated and hearings were held.

On May 26, 1942, the Commission entered its order and made its findings. Its order required Hope to decrease its future interstate rates so as to reflect a reduction, on an annual basis of not less than $3,609,857 in operating revenues. And it established 'just and reasonable' average rates per m.c.f. for each of the five customer companies. [3] In response to the prayer of the City of Cleveland the Commission also made findings as to the lawfulness of past rates, although concededly it had no authority under the Act to fix past rates or to award reparations. 44 P.U.R.,U.S., at page 34. It found that the rates collected by Hope from East Ohio were unjust, unreasonable, excessive and therefore unlawful, by $830,892 during 1939, $3,219,551 during 1940, and $2,815,789 on an annual basis since 1940. It further found that just, reasonable, and lawful rates for gas sold by Hope to East Ohio for resale for ultimate public consumption were those required ***596** to produce $11,528,608 for 1939, $11,507,185 for 1940 and $11.910,947 annually since 1940.

The Commission established an interstate rate base of $33,712,526 which, it found, represented the 'actual legitimate cost' of the company's interstate property less depletion and depreciation and plus unoperated acreage, working capital and future net capital additions. The Commission, beginning with book cost, made ****285** certain adjustments not necessary to relate here and found the 'actual legitimate cost' of the plant in interstate service to be $51,957,416, as of December 31, 1940. It deducted accrued depletion and depreciation, which it found to be $22,328,016 on an 'economic-service-life' basis. And it added $1,392,021 for future net capital additions, $566,105 for useful unoperated acreage, and $2,125,000 for working capital. It used 1940 as a test year to estimate future revenues and expenses. It allowed over $16,000,000 as annual operating expenses—about $1,300,000 for taxes, $1,460,000 for depletion and depreciation, $600,000 for exploration and development costs, $8,500,000 for gas purchased. The Commission allowed a net increase of $421,160 over 1940 operating expenses, which amount was to take care of future increase in wages, in West Virginia property taxes, and in exploration and development costs. The total amount of deductions allowed from interstate revenues was $13,495,584.

Hope introduced evidence from which it estimated reproduction cost of the property at $97,000,000. It also presented a so-called trended 'original cost' estimate which exceeded $105,000,000. The latter was designed 'to indicate what the original cost of the property would have been if

1938 material and labor prices had prevailed throughout the whole period of the piece-meal construction of the company's property since 1898.' 44 P.U.R.,N.S., at pages 8, 9. Hope estimated by the 'percent condition' method accrued depreciation at about 35% of ***597** reproduction cost new. On that basis Hope contended for a rate base of $66,000,000. The Commission refused to place any reliance on reproduction cost new, saying that it was 'not predicated upon facts' and was 'too conjectural and illusory to be given any weight in these proceedings.' Id., 44 P.U.R.,U.S., at page 8. It likewise refused to give any 'probative value' to trended 'original cost' since it was 'not founded in fact' but was 'basically erroneous' and produced 'irrational results.' Id., 44 P.U.R., N.S., at page 9. In determining the amount of accrued depletion and depreciation the Commission, following Lindheimer v. Illinois Bell Telephone Co., 292 U.S. 151, 167-169, 54 S.Ct. 658, 664—666, 78 L.Ed. 1182; Federal Power Commission v. Natural Gas Pipeline Co., 315 U.S. 575, 592, 593, 62 S.Ct. 736, 745, 746, 86 L.Ed. 1037, based its computation on 'actual legitimate cost'. It found that Hope during the years when its business was not under regulation did not observe 'sound depreciation and depletion practices' but 'actually accumulated an excessive reserve'[4] of about $46,000,000. Id., 44 P.U.R.,N.S., at page 18. One member of the Commission thought that the entire amount of the reserve should be deducted from 'actual legitimate cost' in determining the rate base.[5] The majority of the ***598** Commission concluded, however, that where, as here, a business is brought under regulation for the first time and where incorrect depreciation and depletion practices have prevailed, the deduction of the reserve requirement (actual existing depreciation and depletion) rather than the excessive reserve should be made so as to ****286** lay 'a sound basis for future regulation and control of rates.' Id., 44 P.U.R.,N.S., at page 18. As we have pointed out, it determined accrued depletion and depreciation to be $22,328,016; and it allowed approximately $1,460,000 as the annual operating expense for depletion and depreciation.[6]

Hope's estimate of original cost was about $69,735,000—approximately $17,000,000 more than the amount found by the Commission. The item of $17,000,000 was made up largely of expenditures which prior to December 31, 1938, were charged to operating expenses. Chief among those expenditures was some $12,600,000 expended ***599** in well-drilling prior to 1923. Most of that sum was expended by Hope for labor, use of drilling-rigs, hauling, and similar costs of well-drilling. Prior to 1923 Hope followed the general practice of the natural gas industry and charged the cost of drilling wells to operating expenses. Hope continued that practice until the Public Service Commission of West Virginia in 1923 required it to capitalize such expenditures, as does the Commission under its present Uniform System of Accounts.[7] The Commission refused to add such items to the rate base stating that 'No greater injustice to consumers could be done than to allow items as operating expenses and at a later date include them in the rate base, thereby placing multiple charges upon the consumers.' Id., 44 P.U.R.,N.S., at page 12. For the same reason the Commission excluded from the rate base about $1,600,000 of expenditures on properties which Hope acquired from other utilities, the latter having charged those payments to operating expenses. The Commission disallowed certain other overhead items amounting to over $3,000,000 which also had been previously charged to operating expenses. And it refused to add some $632,000 as interest during construction since no interest was in fact paid.

Hope contended that it should be allowed a return of not less than 8%. The Commission found that an 8% return would be unreasonable but that 6 1/2% was a fair rate of return. That rate of return, applied to the rate base of $33,712,526, would produce $2,191,314 annually, as compared with the present income of not less than $5,801,171.

The Circuit Court of Appeals set aside the order of the Commission for the following reasons. (1) It held that the rate base should reflect the 'present fair value' of the ***600** property, that the Commission in determining the 'value' should have considered reproduction cost and trended original cost, and that 'actual legitimate cost' (prudent investment) was not the proper measure of 'fair value' where price levels had changed since the investment. (2) It concluded that the well-drilling costs and overhead items in the amount of some $17,000,000 should have been included in the rate base. (3) It held that accrued depletion and depreciation and the annual allowance for that expense should be computed on the basis of 'present fair value' of the property not on the basis of 'actual legitimate cost'.

****287** The Circuit Court of Appeals also held that the Commission had no power to make findings as to past rates in aid of state regulation. But it concluded that those findings were proper as a step in the process of fixing future rates. Viewed in that light, however, the findings were deemed to be invalidated by the same errors which vitiated the findings on which the rate order was based.

Order Reducing Rates. Congress has provided in s 4(a) of the Natural Gas Act that all natural gas rates subject to the jurisdiction of the Commission 'shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.' Sec. 5(a) gives the Commission the power, after hearing, to determine the 'just and reasonable rate' to be thereafter observed and to fix the rate by order. Sec. 5(a) also empowers the Commission to order a 'decrease where existing rates are unjust * * * unlawful, or are not the lowest reasonable rates.' And Congress has provided in s 19(b) that on review of these rate orders the 'finding of the Commission as to the facts, if supported by substantial evidence, shall be conclusive.' Congress, however, has provided no formula by which the 'just and reasonable' rate is to be determined. It has not filled in the ***601** details of the general prescription [8] of s 4(a) and s 5(a). It has not expressed in a specific rule the fixed principle of 'just and reasonable'.

[1] **[2]** When we sustained the constitutionality of the Natural Gas Act in the Natural Gas Pipeline Co. case, we stated that the 'authority of Congress to regulate the prices of commodities in interstate commerce is at least as great under the Fifth Amendment as is that of the states under the Fourteenth to regulate the prices of commodities in intrastate commerce.' 315 U.S. at page 582, 62 S.Ct. at page 741, 86 L.Ed. 1037. Rate-making is indeed but one species of price-fixing. Munn v. Illinois, 94 U.S. 113, 134, 24 L.Ed. 77. The fixing of prices, like other applications of the police power, may reduce the value of the property which is being regulated. But the fact that the value is reduced does not mean that the regulation is invalid. Block v. Hirsh, 256 U.S. 135, 155—157, 41 S.Ct. 458, 459, 460, 65 L.Ed. 865, 16 A.L.R. 165; Nebbia v. New York, 291 U.S. 502, 523—539, 54 S.Ct. 505, 509—517, 78 L.Ed. 940, 89 A.L.R. 1469, and cases cited. It does, however, indicate that 'fair value' is the end product of the process of rate-making not the starting point as the Circuit Court of Appeals held. The heart of the matter is that rates cannot be made to depend upon 'fair value' when the value of the going enterprise depends on earnings under whatever rates may be anticipated. [9]

***602** **[3]** **[4]** **[5]** **[6]** **[7]** We held in Federal Power Commission v. Natural Gas Pipeline Co., supra, that the Commission was not bound to the use of any single formula or combination of formulae in determining rates. Its rate-making function, moreover, involves the making of 'pragmatic adjustments.' Id., 315 U.S. at page 586, 62 S.Ct. at page 743, 86 L.Ed. 1037. And when the Commission's order is challenged in the courts, the question is whether that order 'viewed in its entirety' meets the requirements of the Act. Id., 315 U.S. at page 586, 62 S.Ct. at page 743, 86 L.Ed. 1037. Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling. Cf. ****288** Los Angeles Gas & Electric Corp. v. Railroad Commission, 289 U.S. 287, 304, 305, 314, 53 S.Ct. 637, 643, 644, 647, 77 L.Ed. 1180; West Ohio Gas Co. v. Public Utilities Commission (No. 1), 294 U.S. 63, 70, 55 S.Ct. 316, 320, 79 L.Ed. 761; West v. Chesapeake & Potomac Tel. Co., 295 U.S. 662, 692, 693, 55 S.Ct. 894, 906, 907, 79 L.Ed. 1640 (dissenting opinion). It is not theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end. The fact that the method employed to reach that result may contain infirmities is not then important. Moreover, the Commission's order does not become suspect by reason of the fact that it is challenged. It is the product of expert judgment which carries a presumption of validity. And he who would upset the rate order under the Act carries the heavy burden of making a convincing showing that it is invalid because it is unjust and unreasonable in its consequences. Cf. Railroad Commission v. Cumberland Tel. & T. Co., 212 U.S. 414, 29 S.Ct. 357, 53 L.Ed. 577; Lindheimer v. Illinois Bell Tel. Co., supra, 292 U.S. at pages 164, 169, 54 S.Ct. at pages 663, 665, 78 L.Ed. 1182; Railroad Commission v. Pacific Gas & E. Co., 302 U.S. 388, 401, 58 S.Ct. 334, 341, 82 L.Ed. 319.

***603** **[8]** **[9]** The rate-making process under the Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline Co. case that 'regulation does not insure that the business shall produce net revenues.' 315 U.S. at page 590, 62 S.Ct. at page 745, 86 L.Ed. 1037. But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. Cf. Chicago & Grand Trunk R. Co. v. Wellman, 143 U.S. 339, 345, 346, 12 S.Ct. 400, 402, 36 L.Ed. 176. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. See State of Missouri ex rel. Southwestern Bell Tel. Co. v. Public Service Commission, 262 U.S. 276, 291, 43 S.Ct. 544, 547, 67 L.Ed. 981, 31 A.L.R. 807 (Mr. Justice Brandeis concurring). The conditions under which more or less might be allowed are not important here. Nor is it important to this case to determine the various permissible ways in which any rate base on which the return is computed might be arrived at. For we are of the view that the end result in this case cannot be condemned under the Act as unjust and unreasonable from the investor or company viewpoint.

We have already noted that Hope is a wholly owned subsidiary of the Standard Oil Co. (N.J.). It has no securities outstanding except stock. All of that stock has been owned by Standard since 1908. The par amount presently outstanding is approximately $28,000,000 as compared with the rate base of $33,712,526 established by ***604** the Commission. Of the total outstanding stock $11,000,000 was issued in stock dividends. The balance, or about $17,000,000, was issued for cash or other assets. During the four decades of its operations Hope has paid over $97,000,000 in cash dividends. It had, moreover, accumulated by 1940 an earned surplus of about $8,000,000. It had thus earned the total investment in the company nearly seven times. Down to 1940 it earned over 20% per year on the average annual amount of its capital stock issued for cash or other assets. On an average invested capital of some $23,000,000 Hope's average earnings have been about 12% a year. And during this period it had accumulated in addition reserves for depletion and depreciation of about $46,000,000. Furthermore, during 1939, 1940 and 1941, Hope paid dividends of 10% on its stock. And in the year 1942, during about half of which the lower rates were in effect, it paid dividends of 7 1/2%. From 1939-1942 its earned surplus increased from $5,250,000 to about $13,700,000, i.e., to almost half the par value of its outstanding stock.

As we have noted, the Commission fixed a rate of return which permits Hope to earn $2,191,314 annually. In determining that amount it stressed the importance of maintaining the financial integrity of the ****289** company. It considered the financial history of Hope and a vast array of data bearing on the natural gas industry, related businesses, and general economic conditions. It noted that the yields on better issues of bonds of natural gas companies sold in the last few years were 'close to 3 per cent', 44 P.U.R.,N.S., at page 33. It stated that the company was a 'seasoned enterprise whose risks have been minimized' by adequate provisions for depletion and depreciation (past and present) with 'concurrent high profits', by 'protected established markets, through affiliated distribution companies, in populous and industralized areas', and by a supply of gas locally to meet all requirements, ***605** 'except on certain peak days in the winter, which it is feasible to supplement in the future with gas from other sources.' Id., 44 P.U.R.,N.S., at page 33. The Commission concluded, 'The company's efficient management, established markets, financial record, affiliations, and its prospective business place it in a strong position to attract capital upon favorable terms when it is required.' Id., 44 P.U.R.,N.S., at page 33.

[10] **[11]** **[12]** In view of these various considerations we cannot say that an annual return of $2,191,314 is not 'just and reasonable' within the meaning of the Act. Rates which enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed certainly cannot be condemned as invalid, even though they might produce only a meager return on the so-called 'fair value' rate base. In that connection it will be recalled that Hope contended for a rate base of $66,000,000 computed on reproduction cost new. The Commission points out that if that rate base were accepted, Hope's average rate of return for the four-year period from 1937-1940 would amount to 3.27%. During that period Hope earned an annual average return of about 9% on the average investment. It asked for no rate increases. Its properties were well maintained and operated. As the Commission says such a modest rate of 3.27% suggests an 'inflation of the base on which the rate has been computed.' Dayton Power & Light Co. v. Public Utilities Commission, 292 U.S. 290, 312, 54 S.Ct. 647, 657, 78 L.Ed. 1267. Cf. Lindheimer v. Illinois Bell Tel. Co., supra, 292 U.S. at page 164, 54 S.Ct. at page 663, 78 L.Ed. 1182. The incongruity between the actual operations and the return computed on the basis of reproduction cost suggests that the Commission was wholly justified in rejecting the latter as the measure of the rate base.

In view of this disposition of the controversy we need not stop to inquire whether the failure of the Commission to add the $17,000,000 of well-drilling and other costs to ***606** the rate base was consistent with the prudent investment theory as developed and applied in particular cases.

[13] **[14]** **[15]** Only a word need be added respecting depletion and depreciation. We held in the Natural Gas Pipeline Co. case that there was no constitutional requirement 'that the owner who embarks in a wasting-asset business of limited life shall receive at the end more than he has put into it.' 315 U.S. at page 593, 62 S.C. at page 746, 86 L.Ed. 1037. The Circuit Court of Appeals did not think that that rule was applicable here because Hope was a utility required to continue its service to the public and not scheduled to end its business on a day certain as was stipulated to be true of the Natural Gas Pipeline Co. But that distinction is quite immaterial. The ultimate exhaustion of the supply is inevitable in the case of all natural gas companies. Moreover, this Court recognized in Lindheimer v. Illinois Bell Tel. Co., supra, the propriety of basing annual depreciation on cost. [10] By such a procedure the ****290** utility is made whole and the integrity of its investment maintained. [11] No more is required. [12] We cannot approve the contrary holding ***607** of United Railways & Electric Co. v. West, 280 U.S. 234, 253, 254, 50 S.Ct. 123, 126, 127, 74 L.Ed. 390. Since there are no constitutional requirements more exacting than the standards of the Act, a rate order which conforms to the latter does not run afoul of the former.

The Position of West Virginia. The State of West Virginia, as well as its Public Service Commission, intervened in the proceedings before the Commission and participated in the hearings before it. They have also filed a brief amicus curiae here and have participated in the argument at the bar. Their contention is that the result achieved by the rate order 'brings consequences which are unjust to West Virginia and its citizens' and which 'unfairly depress the value of gas, gas lands and gas leaseholds, unduly restrict development of their natural resources, and arbitrarily transfer their properties to the residents of other states without just compensation therefor.'

West Virginia points out that the Hope Natural Gas Co. holds a large number of leases on both producing and unoperated properties. The owner or grantor receives from the operator or grantee delay rentals as compensation for postponed drilling. When a producing well is successfully brought in, the gas lease customarily continues indefinitely for the life of the field. In that case the operator pays a stipulated gas-well rental or in some cases a gas royalty equivalent to one-eighth of the gas marketed. [13] Both the owner and operator have valuable property interests in the gas which are separately taxable under West Virginia law. The contention is that the reversionary interests in the leaseholds should be represented in the rate proceedings since it is their gas which is being sold in interstate ***608** commerce. It is argued, moreover, that the owners of the reversionary interests should have the benefit of the 'discovery value' of the gas leaseholds, not the interstate consumers. Furthermore, West Virginia contends that the Commission in fixing a rate for natural gas produced in that State should consider the effect of the rate order on the economy of West Virginia. It is pointed out that gas is a wasting asset with a rapidly diminishing supply. As a result West Virginia's gas deposits are becoming increasingly valuable. Nevertheless the rate fixed by the Commission reduces that value. And that reduction, it is said, has severe repercussions on the economy of the State. It is argued in the first place that as a result of this rate reduction Hope's West Virginia property taxes may be decreased in view of the relevance which earnings have under West Virginia law in the assessment of property for tax purposes. [14] Secondly, it is pointed out that West Virginia has a production tax [15] on the 'value' of the gas exported from the State. And we are told that for purposes of that tax 'value' becomes under West Virginia law 'practically the substantial equivalent of market value.' Thus West Virginia argues that undervaluation of Hope's gas leaseholds will cost the State many thousands of dollars in taxes. The effect, it is urged, is to impair West Virginia's tax structure for the benefit of Ohio and Pennsylvania consumers. West Virginia emphasizes, moreover, its deep interest in the conservation of its natural resources including its natural gas. It says that a reduction of the value of these leasehold values will jeopardize these conservation policies in three respects: (1) ****291** exploratory development of new fields will be discouraged; (2) abandonment of lowyield high-cost marginal wells will be hastened; and (3) secondary recovery of oil will be hampered. ***609** Furthermore, West Virginia contends that the reduced valuation will harm one of the great industries of the State and that harm to that industry must inevitably affect the welfare of the citizens of the State. It is also pointed out that West Virginia has a large interest in coal and oil as well as in gas and that these forms of fuel are competitive. When the price of gas is materially cheapened, consumers turn to that fuel in preference to the others. As a result this lowering of the price of natural gas will have the effect of depreciating the price of West Virginia coal and oil.

West Virginia insists that in neglecting this aspect of the problem the Commission failed to perform the function which Congress entrusted to it and that the case should be remanded to the Commission for a modification of its order. [16]

We have considered these contentions at length in view of the earnestness with which they have been urged upon us. We have searched the legislative history of the Natural Gas Act for any indication that Congress entrusted to the Commission the various considerations which West Virginia has advanced here. And our conclusion is that Congress did not.

[16] **[17]** We pointed out in Illinois Natural Gas Co. v. Central Illinois Public Service Co., 314 U.S. 498, 506, 62

S.Ct. 384, 387, 86 L.Ed. 371, that the purpose of the Natural Gas Act was to provide, 'through the exercise of the national power over interstate commerce, an agency for regulating the wholesale distribution to public service companies of natural gas moving interstate, which this Court had declared to be interstate commerce not subject to certain types of state regulation.' As stated in the House Report the 'basic purpose' of this legislation was 'to occupy' the field in which such cases as ***610** State of Missouri v. Kansas Natural Gas Co., 265 U.S. 298, 44 S.Ct. 544, 68 L.Ed. 1027, and Public Utilities Commission v. Attleboro Steam & Electric Co., 273 U.S. 83, 47 S.Ct. 294, 71 L.Ed. 549, had held the States might not act. H.Rep. No. 709, 75th Cong., 1st Sess., p. 2. In accomplishing that purpose the bill was designed to take 'no authority from State commissions' and was 'so drawn as to complement and in no manner usurp State regulatory authority.' Id., p. 2. And the Federal Power Commission was given no authority over the 'production or gathering of natural gas.' s 1(b).

[18] The primary aim of this legislation was to protect consumers against exploitation at the lands of natural gas companies. Due to the hiatus in regulation which resulted from the Kansas Natural Gas Co. case and related decisions state commissions found it difficult or impossible to discover what it cost interstate pipe-line companies to deliver gas within the consuming states; and thus they were thwarted in local regulation. H.Rep., No. 709, supra, p. 3. Moreover, the investigations of the Federal Trade Commission had disclosed that the majority of the pipe-line mileage in the country used to transport natural gas, together with an increasing percentage of the natural gas supply for pipe-line transportation, had been acquired by a handful of holding companies.[17] State commissions, independent producers, and communities having or seeking the service were growing quite helpless against these combinations.[18] These were the types of problems with which those participating in the hearings were pre-occupied.[19] Congress addressed itself to those specific evils.

***611** The Federal Power Commission was given ****292** broad powers of regulation. The fixing of 'just and reasonable' rates (s 4) with the powers attendant thereto[20] was the heart of the new regulatory system. Moreover, the Commission was given certain authority by s 7(a), on a finding that the action was necessary or desirable 'in the public interest,' to require natural gas companies to extend or improve their transportation facilities and to sell gas to any authorized local distributor. By s 7(b) it was given control over the abandonment of facilities or of service. And by s 7(c), as originally enacted, no natural gas company could undertake the construction or extension of any facilities for the transportation of natural gas to a market in which natural gas was already being served by another company, or sell any natural gas in such a market, without obtaining a certificate of public convenience and necessity from the Commission. In passing on such applications for certificates of convenience and necessity the Commission was told by s 7(c), as originally enacted, that it was 'the intention of Congress that natural gas shall be sold in interstate commerce for resale for ultimate public consumption for domestic, commercial, industrial, or any other use at the lowest possible reasonable rate consistent with the maintenance of adequate service in the public interest.' The latter provision was deleted from s 7(c) when that subsection was amended by the Act of February 7, 1942, 56 Stat. 83. By that amendment limited grandfather rights were granted companies desiring to extend their facilities and services over the routes or within the area which they were already serving. Moreover, s 7(c) was broadened so as to require certificates ***612** of public convenience and necessity not only where the extensions were being made to markets in which natural gas was already being sold by another company but in other situations as well.

[19] These provisions were plainly designed to protect the consumer interests against exploitation at the hands of private natural gas companies. When it comes to cases of abandonment or of extensions of facilities or service, we may assume that, apart from the express exemptions[21] contained in s 7, considerations of conservation are material to the issuance of certificates of public convenience and necessity. But the Commission was not asked here for a certificate of public convenience and necessity under s 7 for any proposed construction or extension. It was faced with a determination of the amount which a private operator should be allowed to earn from the sale of natural gas across state lines through an established distribution system. Secs. 4 and 5, not s 7, provide the standards for that determination. We cannot find in the words of the Act or in its history the slightest intimation or suggestion that the exploitation of consumers by private operators through the maintenance of high rates should be allowed to continue provided the producing states obtain indirect benefits from it. That apparently was the Commission's view of the matter, for the same arguments advanced here were presented to the Commission and not adopted by it.

We do not mean to suggest that Congress was unmindful of the interests of the producing states in their natural gas supplies when it drafted the Natural Gas Act. As we have said, the Act does not intrude on the domain traditionally reserved for control by state commissions; and the Federal Power Commission was given no authority over ***613** 'the production or gathering of natural gas.' s 1(b). In addition, Congress recognized the legitimate interests of the States in the conservation of natural gas. By s 11 Congress instructed the Commission to make reports on compacts between two or more States dealing with the conservation, production and transportation of natural gas.[22] The Commission was also ****293** directed to recommend further legislation appropriate or necessary to carry out any proposed compact and 'to aid in the conservation of natural-gas resources within the United States and in the orderly, equitable, and economic production, transportation, and distribution of natural gas.' s 11(a). Thus Congress was quite aware of the interests of the producing states in their natural gas supplies.[23] But it left the protection of ***614** those interests to measures other than the maintenance of high rates to private companies. If the Commission is to be compelled to let the stockholders of natural gas companies have a feast so that the producing states may receive crumbs from that table, the present Act must be redesigned. Such a project raises questions of policy which go beyond our province.

[20] It is hardly necessary to add that a limitation on the net earnings of a natural gas company from its interstate business is not a limitation on the power of the producing state either to safeguard its tax revenues from that industry[24] or to protect the interests of those who sell their gas to the interstate operator.[25] The return which ****294** the Commission ***615** allowed was the net return after all such charges.

It is suggested that the Commission has failed to perform its duty under the Act in that it has not allowed a return for gas production that will be enough to induce private enterprise to perform completely and efficiently its functions for the public. The Commission, however, was not oblivious of those matters. It considered them. It allowed, for example, delay rentals and exploration and development costs in operating expenses.[26] No serious attempt has been made here to show that they are inadequate. We certainly cannot say that they are, unless we are to substitute our opinions for the expert judgment of the administrators to whom Congress entrusted the decision. Moreover, if in light of experience they turn out to be inadequate for development of new sources of supply, the doors of the Commission are open for increased allowances. This is not an order for all time. The Act contains machinery for obtaining rate adjustments. s 4.

[21] **[22]** But it is said that the Commission placed too low a rate on gas for industrial purposes as compared with gas for domestic purposes and that industrial uses should be discouraged. It should be noted in the first place that the rates which the Commission has fixed are Hope's interstate wholesale rates to distributors not interstate rates to industrial users[27] and domestic consumers. We hardly ***616** can assume, in view of the history of the Act and its provisions, that the resales intrastate by the customer companies which distribute the gas to ultimate consumers in Ohio and Pennsylvania are subject to the rate-making powers of the Commission.[28] But in any event those rates are not in issue here. Moreover, we fail to find in the power to fix 'just and reasonable' rates the power to fix rates which will disallow or discourage resales for industrial use. The Committee Report stated that the Act provided 'for regulation along recognized and more or less standardized lines' and that there was 'nothing novel in its provisions'. H.Rep.No.709, supra, p. 3. Yet if we are now to tell the Commission to fix the rates so as to discourage particular uses, we would indeed be injecting into a rate case a 'novel' doctrine which has no express statutory sanction. The same would be true if we were to hold that the wasting-asset nature of the industry required the maintenance of the level of rates so that natural gas companies could make a greater profit on each unit of gas sold. Such theories of rate-making for this industry may or may not be desirable. The difficulty is that s 4(a) and s 5(a) contain only the conventional standards of rate-making for natural gas companies.[29] The ***617** Act of February 7, 1942, by broadening s 7 gave the Commission some additional authority to deal with the conservation aspects of the problem.[30] But s 4(a) and s 5(a) were not changed. If the standard ****295** of 'just and reasonable' is to sanction the maintenance of high rates by a natural gas company because they restrict the use of natural gas for certain purposes, the Act must be further amended.

[23] **[24]** It is finally suggested that the rates charged by Hope are discriminatory as against domestic users and in favor of industrial users. That charge is apparently based on s 4(b) of the Act which forbids natural gas companies from maintaining 'any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.' The power of the Commission to eliminate any such unreasonable differences or discriminations is plain. s 5(a). The Commission, however, made no findings under s 4(b). Its failure in that regard was not challenged in the petition to review. And it has not been raised or argued here by any party. Hence the problem of discrimination has no proper place in the present decision. It will be time enough to pass on that issue when it is presented to us. Congress has entrusted the administration of the Act to the Commission not to the courts. Apart from the requirements of judicial review it is not ***618** for us to advise the Commission how to discharge its functions.

Findings as to the Lawfulness of Past Rates. As we have noted, the Commission made certain findings as to the lawfulness of past rates which Hope had charged its interstate customers. Those findings were made on the complaint of the City of Cleveland and in aid of state regulation. It is conceded that under the Act the Commission has no power to make reparation orders. And its power to fix rates admittedly is limited to those 'to be thereafter observed and in force.' s 5(a). But the Commission maintains that it has the power to make findings as to the lawfulness of past rates even though it has no power to fix those rates.[31] However that may be, we do not think that these findings were reviewable under s 19(b) of the Act. That section gives any party 'aggrieved by an order' of the Commission a review 'of such order' in the circuit court of appeals for the circuit where the natural gas company is located or has its principal place of business or in the United States Court of Appeals for the District of Columbia. We do not think that the findings in question fall within that category. **[25]** **[26]** The Court recently summarized the various types of administrative action or determination reviewable as orders under the Urgent Deficiencies Act of October 22, ***619** 1913, 28 U.S.C. ss 45, 47a, 28 U.S.C.A. ss 45, 47a, and kindred statutory provisions. Rochester Tel. Corp. v. United States, 307 U.S. 125, 59 S.Ct. 754, 83 L.Ed. 1147. It was there pointed out that where 'the order sought to be reviewed does not of itself adversely affect complainant but only affects his rights adversely on the contingency of future administrative action', it is not reviewable. Id., 307 U.S. at page 130, 59 S.Ct. at page 757, 83 L.Ed. 1147. The Court said, 'In view of traditional conceptions of federal judicial power, resort to the courts in these situations is either premature or wholly beyond their province.' ****296** Id., 307 U.S. at page 130, 59 S.Ct. at page 757, 83 L.Ed. 1147. And see United States v. Los Angeles S.L.R. C/O., 273 U.S. 299, 309, 310, 47 S.CT. 413, 414, 415, 71 L.ED. 651; SHANNAHAN V. UNITED STATES, 303 U.S. 596, 58 S.CT. 732, 82 L.ED. 1039. THESE CONSIDERATIONS ARE APPOSITE HERE. THE COMMISSION HAS NO AUTHORITY TO ENFORCE THESE FINDINGS. THEY ARE 'THE EXERCISE SOLELY OF THE FUNCTION OF INVESTIGATION.' UNITED STATES V. LOS ANGELES & S.L.R. CO., SUPRA, 273 U.S. AT PAGE 310, 47 S.CT. AT PAGE 414, 71 L.ED. 651. THEY ARE ONLY A PRELIMINARY, INTERIM STEP TOWARDS POSSIBLE FUTURE ACTION—ACTION NOT BY THE COMMISSION BUT BY WHOLLY INDEPENDENT AGENCIES. THE OUTCOME OF THOSE PROCEEDINGS MAY TURN ON FACTORS OTHER THAN THESE FINDINGS. THESE FINDINGS MAY NEVER RESULT IN THE RESPONDENT FEELING THE PINCH OF ADMINISTRATIVE ACTION.

Reversed.

Mr. Justice ROBERTS took no part in the consideration or decision of this case.

Opinion of Mr. Justice BLACK and Mr. Justice MURPHY.

We agree with the Court's opinion and would add nothing to what has been said but for what is patently a wholly gratuitous assertion as to Constitutional law in the dissent of Mr. Justice FRANKFURTER. We refer to the statement that 'Congressional acquiescence to date in the doctrine of Chicago, etc., R. Co. v. Minnesota, supra (134 U.S. 418, 10 S.Ct. 462, 702, 33 L.Ed. 970), may fairly be claimed.' That was the case in which a majority of this Court was finally induced to expand the meaning ***620** of 'due process' so as to give courts power to block efforts of the state and national governments to regulate economic affairs. The present case does not afford a proper occasion to discuss the soundness of that doctrine because, as stated in Mr. Justice FRANKFURTER'S dissent, 'That issue is not here in controversy.' The salutary practice whereby courts do not discuss issues in the abstract applies with peculiar force to Constitutional questions. Since, however, the dissent adverts to a highly controversial due process doctrine and implies its acceptance by Congress, we feel compelled to say that we do not understand that Congress voluntarily has acquiesced in a Constitutional principle of government that courts, rather than legislative bodies, possess final authority over regulation of economic affairs. Even this Court has not always fully embraced that principle, and we wish to repeat that we have never acquiesced in it, and do not now. See Federal Power Commission v. Natural Gas Pipeline Co., 315 U.S. 575, 599-601, 62 S.Ct. 736, 749, 750, 86 L.Ed. 1037.

Mr. Justice REED, dissenting.

This case involves the problem of rate making under the Natural Gas Act. Added importance arises from the obvious fact that the principles stated are generally applicable to all federal agencies which are entrusted with the determination of rates for utilities. Because my views differ somewhat from those of my brethren, it may be of some value to set them out in a summary form.

The Congress may fix utility rates in situations subject to federal control without regard to any standard except the constitutional standards of due process and for taking private property for public use without just compensation. Wilson v. New, 243 U.S. 332, 350, 37 S.Ct. 298, 302, 61 L.Ed. 755, L.R.A.1917E, 938, Ann.Cas.1918A, 1024. A Commission, however, does not have this freedom of action. Its powers are limited not only by the constitutional standards but also by the standards of the delegation. Here the standard added by the Natural Gas Act is that the rate be 'just ***621** and reasonable.'[1] Section 6[2] ****297** throws additional light on the meaning of these words.

When the phrase was used by Congress to describe allowable rates, it had relation to something ascertainable. The rates were not left to the whim of the Commission. The rates fixed would produce an annual return and that annual return was to be compared with a theoretical just and reasonable return, all risks considered, on the fair value of the property used and useful in the public service at the time of the determination.

Such an abstract test is not precise. The agency charged with its determination has a wide range before it could properly be said by a court that the agency had disregarded statutory standards or had confiscated the property of the utility for public use. Cf. Chicago, M. & St. P.R. Co. v. Minnesota, 134 U.S. 418, 461—466, 10 S.Ct. 462, 702, 703—705, 33 L.Ed. 970, dissent. This is as Congress intends. Rates are left to an experienced agency particularly competent by training to appraise the amount required.

The decision as to a reasonable return had not been a source of great difficulty, for borrowers and lenders reached such agreements daily in a multitude of situations; and although the determination of fair value had been troublesome, its essentials had been worked out in fairness to investor and consumer by the time of the enactment ***622** of this Act. Cf. Los Angeles G. & E. Corp. v. Railroad Comm., 289 U.S. 287, 304 et seq., 53 S.Ct. 637, 643 et seq., 77 L.Ed. 1180. The results were well known to Congress and had that body desired to depart from the traditional concepts of fair value and earnings, it would have stated its intention plainly. Helvering v. Griffiths, 318 U.S. 371, 63 S.Ct. 636.

It was already clear that when rates are in dispute, 'earnings produced by rates do not afford a standard for decision.' 289 U.S. at page 305, 53 S.Ct. at page 644, 77 L.Ed. 1180. Historical cost, prudent investment and reproduction cost[3] were all relevant factors in determining fair value. Indeed, disregarding the pioneer investor's risk, if prudent investment and reproduction cost were not distorted by changes in price levels or technology, each of them would produce the same result. The realization from the risk of an investment in a speculative field, such as natural gas utilities, should be reflected in the present fair value.[4] The amount of evidence to be admitted on any point was of course in the agency's reasonable discretion, and it was free to give its own weight to these or other factors and to determine from all the evidence its own judgment as to the necessary rates.

***623** I agree with the Court in not imposing a rule of prudent investment alone in determining the rate base. This leaves the Commission free, as I understand it, to use any available evidence for its finding of fair value, including both prudent investment and the cost of installing at the present time an efficient system for furnishing the needed utility service.

My disagreement with the Court arises primarily from its view that it makes no ****298** difference how the Commission reached the rate fixed so long as the result is fair and reasonable. For me the statutory command to the Commission is more explicit. Entirely aside from the constitutional problem of whether the Congress could validly delegate its rate making power to the Commission, in toto and without standards, it did legislate in the light of the relation of fair and reasonable to fair value and reasonable return. The Commission must therefore make its findings in observance of that relationship.

The Federal Power Commission did not, as I construe their action, disregard its statutory duty. They heard the evidence relating to historical and reproduction cost and to the reasonable rate of return and they appraised its weight. The evidence of reproduction cost was rejected as unpersuasive, but from the other evidence they found a rate base, which is to me a determination of fair value. On that base the earnings allowed seem fair and reasonable. So far as the Commission went in appraising the property employed in the service, I find nothing in the result which indicates confiscation, unfairness or unreasonableness. Good administration of rate making agencies under this method would avoid undue delay and render revaluations unnecessary except after violent fluctuations of price levels. Rate making under this method has been subjected to criticism. But until Congress changes the standards for the agencies, these rate making bodies should continue the conventional theory of rate ***624** making. It will probably be simpler to improve present methods than to devise new ones.

But a major error, I think was committed in the disregard by the Commission of the investment in exploratory operations and other recognized capital costs. These were not considered by the Commission because they were charged to operating expenses by the company at a time when it was unregulated. Congress did not direct the Commission in rate making to deduct from the rate base capital investment which had been recovered during the unregulated period through excess earnings. In my view this part of the investment should no more have been disregarded in the rate base than any other capital investment which previously had been recovered and paid out in dividends or placed to surplus. Even if prudent investment throughout the life of the property is accepted as the formula for figuring the rate base, it seems to me illogical to throw out the admittedly prudent cost of part of the property because the earnings in the unregulated period had been sufficient to return the prudent cost to the investors over and above a reasonable return. What would the answer be under the theory of the Commission and the Court, if the only prudent investment in this utility had been the seventeen million capital charges which are now disallowed?

For the reasons heretofore stated, I should affirm the action of the Circuit Court of Appeals in returning the proceeding to the Commission for further consideration and should direct the Commission to accept the disallowed capital investment in determining the fair value for rate making purposes.

Mr. Justice FRANKFURTER, dissenting.

My brother JACKSON has analyzed with particularity the economic and social aspects of natural gas as well as ***625** the difficulties which led to the enactment of the Natural Gas Act, especially those arising out of the abortive attempts of States to regulate natural gas utilities. The Natural Gas Act of 1938 should receive application in the light of this analysis, and Mr. Justice JACKSON has, I believe, drawn relevant inferences regarding the duty of the Federal Power Commission in fixing natural gas rates. His exposition seems to me unanswered, and I shall say only a few words to emphasize my basic agreement with him.

For our society the needs that are met by public utilities are as truly public services as the traditional governmental functions of police and justice. They are not less so when these services are rendered by private enterprise under governmental regulation. Who ultimately determines the ways of regulation, is the decisive aspect in the public supervision of privately-owned utilities. Foreshadowed nearly sixty years ago, Railroad Commission Cases (Stone v. Farmers' Loan & Trust Co.), 116 U.S. 307, 331, 6 S.Ct. 334, 344, 388, 1191, 29 L.Ed. 636, it was decided more than fifty ****299** years ago that the final say under the Constitution lies with the judiciary and not the legislature. Chicago, etc., R. Co. v. Minnesota , 134 U.S. 418, 10 S.Ct. 462, 702, 33 L.Ed. 970.

While legal issues touching the proper distribution of governmental powers under the Constitution may always be raised, Congressional acquiescence to date in the doctrine of Chicago, etc., R. Co. v. Minnesota, supra, may fairly be claimed. But in any event that issue is not here in controversy. As pointed out in the opinions of my brethren, Congress has given only limited authority to the Federal Power Commission and made the exercise of that authority subject to judicial review. The Commission is authorized to fix rates chargeable for natural gas. But the rates that it can fix must be 'just and reasonable'. s 5 of the Natural Gas Act, 15 U.S.C. s 717d, 15 U.S.C.A. s 717d. Instead of making the Commission's rate determinations final, Congress ***626** specifically provided for court review of such orders. To be sure, 'the finding of the Commission as to the facts, if supported by substantial evidence' was made 'conclusive', s 19 of the Act, 15 U.S.C. s 717r; 15 U.S.C.A. s 717r. But obedience of the requirement of Congress that rates be 'just and reasonable' is not an issue of fact of which the Commission's own determination is conclusive. Otherwise, there would be nothing for a court to review except questions of compliance with the procedural provisions of the Natural Gas Act. Congress might have seen fit so to cast its legislation. But it has not done so. It has committed to the administration of the Federal Power Commission the duty of applying standards of fair dealing and of reasonableness relevant to the purposes expressed by the Natural Gas Act. The requirement that rates must be 'just and reasonable' means just and reasonable in relation to appropriate standards. Otherwise Congress would have directed the Commission to fix such rates as in the judgment of the Commission are just and reasonable; it would not have also provided that such determinations by the Commission are subject to court review.

To what sources then are the Commission and the courts to go for ascertaining the standards relevant to the regulation of natural gas rates? It is at this point that Mr. Justice JACKSON'S analysis seems to me pertinent. There appear to be two alternatives. Either the fixing of natural gas rates must be left to the unguided discretion of the Commission so long as the rates it fixes do not reveal a glaringly had prophecy of the ability of a regulated utility to continue its service in the future. Or the Commission's rate orders must be founded on due consideration of all the elements of the public interest which the production and distribution of natural gas involve just because it is natural gas. These elements are reflected in the Natural Gas Act, if that Act be applied as an entirety. See, for ***627** instance, ss 4(a)(b)(c)(d), 6, and 11, 15 U.S.C. ss 717c(a)(b)(c)(d), 717e, and 717j, 15 U.S.C.A. ss 717(a—d), 717e, 717j. Of course the statute is not concerned with abstract theories of ratemaking. But its very foundation is the 'public interest', and the public interest is a texture of multiple strands. It includes more than contemporary investors and contemporary consumers. The needs to be served are not restricted to immediacy, and social as well as economic costs must be counted.

It will not do to say that it must all be left to the skill of experts. Expertise is a rational process and a rational process implies expressed reasons for judgment. It will little advance the public interest to substitute for the hodge-podge of the rule in Smyth v. Ames, 169 U.S. 466, 18 S.Ct. 418, 42 L.Ed. 819, an encouragement of conscious obscurity or confusion in reaching a result, on the assumption that so long as the result appears harmless its basis is irrelevant. That may be an appropriate attitude when state action is challenged as unconstitutional. Cf. Driscoll v. Edison Light & Power Co., 307 U.S. 104, 59 S.Ct. 715, 83 L.Ed. 1134. But it is not to be assumed that it was the design of Congress to make the accommodation of the conflicting interests exposed in Mr. Justice JACKSON'S opinion the occasion for a blind clash of forces or a partial assessment of relevant factors, either before the Commission or here.

The objection to the Commission's action is not that the rates it granted were too low but that the range of its vision was too narrow. And since the issues before the Commission involved no less than the ****300** total public interest, the proceedings before it should not be judged by narrow conceptions of common law pleading. And so I conclude that the case should be returned to the Commission. In order to enable this Court to discharge its duty of reviewing the Commission's order, the Commission should set forth with explicitness the criteria by which it is guided ***628** in determining that rates are 'just and reasonable', and it should determine the public interest that is in its keeping in the perspective of the considerations set forth by Mr. Justice JACKSON.

By Mr. Justice JACKSON.

Certainly the theory of the court below that ties rate-making to the fair-value-reproduction-cost formula should be overruled as in conflict with Federal Power Commission v. Natural Gas Pipeline Co.[1] But the case should, I think, be the occasion for reconsideration of our rate-making doctrine as applied to natural gas and should be returned to the Commission for further consideration in the light thereof.

The Commission appears to have understood the effect of the two opinions in the Pipeline case to be at least authority and perhaps direction to fix natural gas rates by exclusive application of the 'prudent investment' rate base theory. This has no warrant in the opinion of the Chief Justice for the Court, however, which released the Commission from subservience to 'any single formula or combination of formulas' provided its order, 'viewed in its entirety, produces no arbitrary result.' 315 U.S. at page 586, 62 S.Ct. at page 743, 86 L.Ed. 1037. The minority opinion I understood to advocate the 'prudent investment' theory as a sufficient guide in a natural gas case. The view was expressed in the court below that since this opinion was not expressly controverted it must have been approved.[2] I disclaim this imputed ***629** approval with some particularity, because I attach importance at the very beginning of federal regulation of the natural gas industry to approaching it as the performance of economic functions, not as the performance of legalistic rituals.

I.

Solutions of these cases must consider eccentricities of the industry which gives rise to them and also to the Act of Congress by which they are governed.

The heart of this problem is the elusive, exhaustible, and irreplaceable nature of natural gas itself. Given sufficient money, we can produce any desired amount of railroad, bus, or steamship transportation, or communications facilities, or capacity for generation of electric energy, or for the manufacture of gas of a kind. In the service of such utilities one customer has little concern with the amount taken by another, one's waste will not deprive another, a volume of service and be created equal to demand, and today's demands will not exhaust or lessen capacity to serve tomorrow. But the wealth of Midas and the wit of man cannot produce or reproduce a natural gas field. We cannot even reproduce the gas, for our manufactured product has only about half the heating value per unit of nature's own. [3]

****301** Natural gas in some quantity is produced in twenty-four states. It is consumed in only thirty-five states, and is ***630** available only to about 7,600,000 consumers. [4] Its availability has been more localized than that of any other utility service because it has depended more on the caprice of nature.

The supply of the Hope Company is drawn from that old and rich and vanishing field that flanks the Appalachian mountains. Its center of production is Pennsylvania and West Virginia, with a fringe of lesser production in New York, Ohio, Kentucky, Tennessee, and the north end of Alabama. Oil was discovered in commercial quantities at a depth of only 69 1/2 feet near Titusville, Pennsylvania, in 1859. Its value then was about $16 per barrel. [5] The oil branch of the petroleum industry went forward at once, and with unprecedented speed. The area productive of oil and gas was roughed out by the drilling of over 19,000 ‘wildcat’ wells, estimated to have cost over $222,000,000. Of these, over 18,000 or 94.9 per cent, were ‘dry holes.’ About five per cent, or 990 wells, made discoveries of commercial importance, 767 of them resulting chiefly in oil and 223 in gas only. [6] Prospecting for many years was a search for oil, and to strike gas was a misfortune. Waste during this period and even later is appalling. Gas was regarded as having no commercial value until about 1882, in which year the total yield was valued only at about $75,000. [7] Since then, contrary to oil, which has become cheaper gas in this field has pretty steadily advanced in price.

While for many years natural gas had been distributed on a small scale for lighting, [8] its acceptance was slow, ***631** facilities for its utilization were primitive, and not until 1885 did it take on the appearance of a substantial industry. [9] Soon monopoly of production or markets developed. [10] To get gas from the mountain country, where it was largely found, to centers of population, where it was in demand, required very large investment. By ownership of such facilities a few corporate systems, each including several companies, controlled access to markets. Their purchases became the dominating factor in giving a market value to gas produced by many small operators. Hope is the market for over 300 such operators. By 1928 natural gas in the Appalachian field commanded an average price of 21.1 cents per m.c.f. at points of production and was bringing 45.7 cents at points of consumption. [11] The companies which controlled markets, however, did not rely on gas purchases alone. They acquired and held in fee or leasehold great acreage in territory proved by ‘wildcat’ drilling. These large marketing system companies as well as many small independent owners and operators have carried on the commercial development of proved territory. The development risks appear from the estimate that up to 1928, 312,318 proved area wells had been sunk in the Appalachian field of which 48,962, or 15.7 per cent, failed to produce oil or gas in commercial quantity. [12]

***632** With the source of supply thus tapped to serve centers of large demand, like Pittsburgh, Buffalo, Cleveland, Youngstown, Akron, and other industrial communities, the distribution of natural gas fast became big business. Its advantages as a ****302** fuel and its price commended it, and the business yielded a handsome return. All was merry and the goose hung high for consumers and gas companies alike until about the time of the first. World War. Almost unnoticed by the consuming public, the whole Appalachian field passed its peak of production and started to decline. Pennsylvania, which to 1928 had given off about 38 per cent of the natural gas from this field, had its peak in 1905; Ohio, which had produced 14 per cent, had its peak in 1915; and West Virginia, greatest producer of all, with 45 per cent to its credit, reached its peak in 1917. [13]

Western New York and Eastern Ohio, on the fringe of the field, had some production but relied heavily on imports from Pennsylvania and West Virginia. Pennsylvania, a producing and exporting state, was a heavy consumer and supplemented her production with imports from West Virginia. West Virginia was a consuming state, but the lion's share of her production was exported. Thus the interest of the states in the North Appalachian supply was in conflict.

Competition among localities to share in the failing supply and the helplessness of state and local authorities in the presence of state lines and corporate complexities is a part of the background of federal intervention in the industry. [14] West Virginia took the boldest measure. It legislated a priority in its entire production in favor of its own inhabitants. That was frustrated by an injunction ***633** from this Court. [15] Throughout the region clashes in the courts and conflicting decisions evidenced public anxiety and confusion. It was held that the New York Public Service Commission did not have power to classify consumers and restrict their use of gas.[16] That Commission held that a company could not abandon a part of its territory and still serve the rest.[17] Some courts admonished the companies to take action to protect consumers.[18] Several courts held that companies, regardless of failing supply, must continue to take on customers, but such compulsory additions were finally held to be within the Public Service Commission's discretion.[19] There were attempts to throw up franchises and quit the service, and municipalities resorted to the courts with conflicting results.[20] Public service commissions of consuming states were handicapped, for they had no control of the supply.[21]

****303** ***634** Shortages during World War I occasioned the first intervention in the natural gas industry by the Federal Government. Under Proclamation of President Wilson the United States Fuel Administrator took control, stopped extensions, classified consumers and established a priority for domestic over industrial use.[22] After the war federal control was abandoned. Some cities once served with natural gas became dependent upon mixed gas of reduced heating value and relatively higher price.[23]

Utilization of natural gas of highest social as well as economic return is domestic use for cooking and water ***635** heating, followed closely by use for space heating in homes. This is the true public utility aspect of the enterprise, and its preservation should be the first concern of regulation. Gas does the family cooking cheaper than any other fuel.[24] But its advantages do not end with dollars and cents cost. It is delivered without interruption at the meter as needed and is paid for after it is used. No money is tied up in a supply, and no space is used for storage. It requires no handling, creates no dust, and leaves no ash. It responds to thermostatic control. It ignites easily and immediately develops its maximum heating capacity. These incidental advantages make domestic life more liveable.

Industrial use is induced less by these qualities than by low cost in competition with other fuels. Of the gas exported from West Virginia by the Hope Company a very substantial part is used by industries. This wholesale use speeds exhaustion of supply and displaces other fuels. Coal miners and the coal industry, a large part of whose costs are wages, have complained of unfair competition from low-priced industrial gas produced with relatively little labor cost.[25]

Gas rate structures generally have favored industrial users. In 1932, in Ohio, the average yield on gas for domestic consumption was 62.1 cents per m.c.f. and on industrial, ***636** 38.7. In Pennsylvania, the figures were 62.9 against 31.7. West Virginia showed the least spread, domestic consumers paying 36.6 cents; and industrial, 27.7.[26] Although this spread is less than ****304** in other parts of the United States,[27] it can hardly be said to be self-justifying. It certainly is a very great factor in hastening decline of the natural gas supply.

About the time of World War I there were occasional and short-lived efforts by some hard-pressed companies to reverse this discrimination and adopt graduated rates, giving a low rate to quantities adequate for domestic use and graduating it upward to discourage industrial use.[28] ***637** These rates met opposition from industrial sources, of course, and since diminished revenues from industrial sources tended to increase the domestic price, they met little popular or commission favor. The fact is that neither the gas companies nor the consumers nor local regulatory bodies can be depended upon to conserve gas. Unless federal regulation will take account of conservation, its efforts seem, as in this case, actually to constitute a new threat to the life of the Appalachian supply.

II.

Congress in 1938 decided upon federal regulation of the industry. It did so after an exhaustive investigation of all aspects including failing supply and competition for the use of natural gas intensified by growing scarcity.[29] Pipelines from the Appalachian area to markets were in the control of a handful of holding company systems.[30] This created a highly concentrated control of the producers' market and of the consumers' supplies. While holding companies dominated both production and distribution they segregated those activities in separate ***638** subsidiaries,[31] the effect of which, if not the purpose, was to isolate ****305** some end of the business from the reach of any one state commission. The cost of natural gas to consumers moved steadily upwards over the years, out of proportion to prices of oil, which, except for the element of competition, is produced under somewhat comparable conditions. The public came to feel that the companies were exploiting the growing scarcity of local gas. The problems of this region had much to do with creating the demand for federal regulation.

The Natural Gas Act declared the natural gas business to be ‘affected with a public interest,’ and its regulation ‘necessary in the public interest.’[32] Originally, and at the time this proceeding was commenced and tried, it also declared 'the intention of Congress that natural gas shall be sold in interstate commerce for resale for ultimate public consumption for domestic, commercial, industrial, or any other use at the lowest possible reasonable rate consistent with the maintenance of adequate service in the public interest.' [33] While this was later dropped, there is nothing to indicate that it was not and is not still an accurate statement of purpose of the Act. Extension or improvement of facilities may be ordered when 'necessary or desirable in the public interest,' abandonment of facilities may be ordered when the supply is 'depleted to the extent that the continuance of service is unwarranted, or that the present or future public convenience or necessity ***639** permit' abandonment and certain extensions can only be made on finding of 'the present or future public convenience and necessity.' [34] The Commission is required to take account of the ultimate use of the gas. Thus it is given power to suspend new schedules as to rates, charges, and classification of services except where the schedules are for the sale of gas 'for resale for industrial use only,' [35] which gives the companies greater freedom to increase rates on industrial gas than on domestic gas. More particularly, the Act expressly forbids any undue preference or advantage to any person or 'any unreasonable difference in rates * * * either as between localities or as between classes of service.' [36] And the power of the Commission expressly includes that to determine the 'just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force.' [37]

In view of the Court's opinion that the Commission in administering the Act may ignore discrimination, it is interesting that in reporting this Bill both the Senate and the House Committees on Interstate Commerce pointed out that in 1934, on a nationwide average the price of natural gas per m.c.f. was 74.6 cents for domestic use, 49.6 cents for commercial use, and 16.9 for industrial use. [38] I am not ready to think that supporters of a bill called attention to the striking fact that householders were being charged five times as much for their gas as industrial users only as a situation which the Bill would do nothing to remedy. On the other hand the Act gave to the Commission what the Court aptly describes as 'broad powers of regulation.'

***640 III.**

This proceeding was initiated by the Cities of Cleveland and Akron. They alleged that the price charged by Hope for natural gas 'for resale to domestic, commercial and small industrial consumers in Cleveland and elsewhere is excessive, unjust, unreasonable, greatly in excess of the price charged by Hope to nonaffiliated companies at wholesale for resale to domestic, commercial and small industrial consumers, and greatly in excess of the price charged by Hope to East Ohio for resale to certain favored industrial consumers in Ohio, and therefore is further unduly discriminatory between consumers and between classes of service' (italics supplied). The company answered admitting differences in prices to affiliated and nonaffiliated companies and justifying them by differences in conditions of delivery. ****306** As to the allegation that the contract price is 'greatly in excess of the price charged by Hope to East Ohio for resale to certain favored industrial consumers in Ohio,' Hope did not deny a price differential, but alleged that industrial gas was not sold to 'favored consumers' but was sold under contract and schedules filed with and approved by the Public Utilities Commission of Ohio, and that certain conditions of delivery made it not 'unduly discriminatory.'

The record shows that in 1940 Hope delivered for industrial consumption 36,523,792 m.c.f. and for domestic and commercial consumption, 50,343,652 m.c.f. I find no separate figure for domestic consumption. It served 43,767 domestic consumers directly, 511,521 through the East Ohio Gas Company, and 154,043 through the Peoples Natural Gas Company, both affiliates owned by the same parent. Its special contracts for industrial consumption, so far as appear, are confined to about a dozen big industries.

***641** Hope is responsible for discrimination as exists in favor of these few industrial consumers. It controls both the resale price and use of industrial gas by virtue of the very interstate sales contracts over which the Commission is exercising its jurisdiction.

Hope's contract with East Ohio Company is an example. Hope agrees to deliver, and the Ohio Company to take, '(a) all natural gas requisite for the supply of the domestic consumers of the Ohio Company; (b) such amounts of natural gas as may be requisite to fulfill contracts made with the consent and approval of the Hope Company by the Ohio Company, or companies which it supplies with natural gas, for the sale of gas upon special terms and conditions for manufacturing purposes.' The Ohio company is required to read domestic customers' meters once a month and meters of industrial customers daily and to furnish all meter readings to Hope. The Hope Company is to have access to meters of all consumers and to all of the Ohio Company's accounts. The domestic consumers of the Ohio Company are to be fully supplied in preference to consumers purchasing for manufacturing purposes and 'Hope Company can be required to supply gas to be used for manufacturing purposes only where the same is sold under special contracts which have first been submitted to and approved in writing by the Hope Company and which expressly provide that natural gas will be supplied thereunder only in so far as the same is not necessary to meet the requirements of domestic consumers supplied through pipe lines of the Ohio Company.' This basic contract was supplemented from time to time, chiefly as to price. The last amendment was in a letter from Hope to East Ohio in 1937. It contained a special discount on industrial gas and a schedule of special industrial contracts, Hope reserving the right to make eliminations therefrom and agreeing that others might be added from time to ***642** time with its approval in writing. It said, 'It is believed that the price concessions contained in this letter, while not based on our costs, are under certain conditions, to our mutual advantage in maintaining and building up the volumes of gas sold by us (italics supplied).' [39]

****307** The Commission took no note of the charges of discrimination and made no disposition of the issue tendered on this point. It ordered a flat reduction in the price per m.c.f. of all gas delivered by Hope in interstate commerce. It made no limitation, condition, or provision as to what classes of consumers should get the benefit of the reduction. While the cities have accepted and are defending the reduction, it is my view that the discrimination of which they have complained is perpetuated and increased by the order of the Commission and that it violates the Act in so doing.

The Commission's opinion aptly characterizes its entire objective by saying that 'bona fide investment figures now become all-important in the regulation of rates.' It should be noted that the all-importance of this theory is not the result of any instruction from Congress. When the Bill to regulate gas was first before Congress it contained ***643** the following: 'In determining just and reasonable rates the Commission shall fix such rate as will allow a fair return upon the actual legitimate prudent cost of the property used and useful for the service in question.' H.R. 5423, 74th Cong., 1st Sess. Title III, s 312(c). Congress rejected this language. See H.R. 5423, s 213 (211(c)), and H.R. Rep. No. 1318, 74th Cong., 1st Sess. 30.

The Commission contends nevertheless that the 'all important' formula for finding a rate base is that of prudent investment. But it excluded from the investment base an amount actually and admittedly invested of some $17,000,000. It did so because it says that the Company recouped these expenditures from customers before the days of regulation from earnings above a fair return. But it would not apply all of such 'excess earnings' to reduce the rate base as one of the Commissioners suggested. The reason for applying excess earnings to reduce the investment base roughly from $69,000,000 to $52,000,000 but refusing to apply them to reduce it from that to some $18,000,000 is not found in a difference in the character of the earnings or in their reinvestment. The reason assigned is a difference in bookkeeping treatment many years before the Company was subject to regulation. The $17,000,000, reinvested chiefly in well drilling, was treated on the books as expense. (The Commission now requires that drilling costs be carried to capital account.) The allowed rate base thus actually was determined by the Company's bookkeeping, not its investment. This attributes a significance to formal classification in account keeping that seems inconsistent with rational rate regulation. [40] Of ***644** course, the ****308** Commission would not and should not allow a rate base to be inflated by bookkeeping which had improperly capitalized expenses. I have doubts about resting public regulation upon any rule that is to be used or not depending on which side it favors.

***645** The Company on the other hand, has not put its gas fields into its calculations on the present-value basis, although that, it contends, is the only lawful rule for finding a rate base. To do so would result in a rate higher than it has charged or proposes as a matter of good business to charge.

The case before us demonstrates the lack of rational relationship between conventional rate-base formulas and natural gas production and the extremities to which regulating bodies are brought by the effort to rationalize them. The Commission and the Company each stands on a different theory, and neither ventures to carry its theory to logical conclusion as applied to gas fields.

IV.

This order is under judicial review not because we interpose constitutional theories between a State and the business it seeks to regulate, but because Congress put upon the federal courts a duty toward administration of a new federal regulatory Act. If we are to hold that a given rate is reasonable just because the Commission has said it was reasonable, review becomes a costly, time-consuming pageant of no practical value to anyone. If on the other hand we are to bring judgment of our own to the task, we should for the guidance of the regulators and the regulated reveal something of the philosophy, be it legal or economic or social, which guides us. We need not be slaves to a formula but unless we can point out a rational way of reaching our conclusions they can only be accepted as resting on intuition or predilection. I must admit that I possess no instinct jby which to know the 'reasonable' from the 'unreasonable' in prices and must seek some conscious design for decision.

The Court sustains this order as reasonable, but what makes it so or what could possibly make it otherwise, ***646** I cannot learn. It holds that: 'it is the result reached not the method employed which is controlling'; 'the fact that the method employed to reach that result may contain infirmities is not then important' and it is not 'important to this case to determine the various permissible ways in which any rate base on which the return is computed might be arrived at.' The Court does lean somewhat on considerations of capitalization and dividend history and requirements for dividends on outstanding stock. But I can give no real weight to that for it is generally and I think deservedly in discredit as any guide in rate cases. [41]

Our books already contain so much talk of methods of rationalizing rates that we must appear ambiguous if we announce results without our working methods. We are confronted with regulation of a unique type of enterprise which I think requires considered rejection of much conventional utility doctrine and adoption of concepts of 'just and reasonable' rates and practices and of the 'public interest' that will take account of the peculiarities of the business.

The Court rejects the suggestions of this opinion. It says that the Committees in reporting the bill which became the Act said it provided 'for regulation along recognized and more or less standardized lines' and that there was 'nothing novel in its provisions.' So saying it sustains a rate calculated on a novel variation of a rate base theory which itself had at the time of enactment of the legislation been recognized only in dissenting opinions. Our difference seems to be between unconscious innovation, [42] and the purposeful ****309** and deliberate innovation I ***647** would make to meet the necessities of regulating the industry before us.

Hope's business has two components of quite divergent character. One, while not a conventional common-carrier undertaking, is essentially a transportation enterprise consisting of conveying gas from where it is produced to point of delivery to the buyer. This is a relatively routine operation not differing substantially from many other utility operations. The service is produced by an investment in compression and transmission facilities. Its risks are those of investing in a tested means of conveying a discovered supply of gas to a known market. A rate base calculated on the prudent investment formula would seem a reasonably satisfactory measure for fixing a return from that branch of the business whose service is roughly proportionate to the capital invested. But it has other consequences which must not be overlooked. It gives marketability and hence 'value' to gas owned by the company and gives the pipeline company a large power over the marketability and hence 'value' of the production of others.

The other part of the business—to reduce to possession an adequate supply of natural gas—is of opposite character, being more erratic and irregular and unpredictable in relation to investment than any phase of any other utility business. A thousand feet of gas captured and severed from real estate for delivery to consumers is recognized under our law as property of much the same nature as a ton of coal, a barrel of oil, or a yard of sand. The value to be allowed for it is the real battleground between the investor and consumer. It is from this part of the business that the chief difference between the parties as to a proper rate base arises.

It is necessary to a 'reasonable' price for gas that it be anchored to a rate base of any kind? Why did courts in the first place begin valuing 'rate bases' in order to 'value' something else? The method came into vogue ***648** in fixing rates for transportation service which the public obtained from common carriers. The public received none of the carriers' physical property but did make some use of it. The carriage was often a monopoly so there were no open market criteria as to reasonableness. The 'value' or 'cost' of what was put to use in the service by the carrier was not a remote or irrelevant consideration in making such rates. Moreover the difficulty of appraising an intangible service was thought to be simplified if it could be related to physical property which was visible and measurable and the items of which might have market value. The court hoped to reason from the known to the unknown. But gas fields turn this method topsy turvy. Gas itself is tangible, possessible, and does have a market and a price in the field. The value of the rate base is more elusive than that of gas. It consists of intangibles—leaseholds and freeholds—operated and unoperated—of little use in themselves except as rights to reach and capture gas. Their value lies almost wholly in predictions of discovery, and of price of gas when captured, and bears little relation to cost of tools and supplies and labor to develop it. Gas is what Hope sells and it can be directly priced more reasonably and easily and accurately than the components of a rate base can be valued. Hence the reason for resort to a roundabout way of rate base price fixing does not exist in the case of gas in the field.

But if found, and by whatever method found, a rate base is little help in determining reasonableness of the price of gas. Appraisal of present value of these intangible rights to pursue fugitive gas depends on the value assigned to the gas when captured. The 'present fair value' rate base, generally in ill repute, [43] is not even ****310** urged by the gas company for valuing its fields.

***649** The prudent investment theory has relative merits in fixing rates for a utility which creates its service merely by its investment. The amount and quality of service rendered by the usual utility will, at least roughly, be measured by the amount of capital it puts into the enterprise. But it has no rational application where there is no such relationship between investment and capacity to serve. There is no such relationship between investment and amount of gas produced. Let us assume that Doe and Roe each produces in West Virginia for delivery to Cleveland the same quantity of natural gas per day. Doe, however, through luck or foresight or whatever it takes, gets his gas from investing $50,000 in leases and drilling. Roe drilled poorer territory, got smaller wells, and has invested $250,000. Does anybody imagine that Roe can get or ought to get for his gas five times as much as Doe because he has spent five times as much? The service one renders to society in the gas business is measured by what he gets out of the ground, not by what he puts into it, and there is little more relation between the investment and the results than in a game of poker.

Two-thirds of the gas Hope handles it buys from about 340 independent producers. It is obvious that the principle of rate-making applied to Hope's own gas cannot be applied, and has not been applied, to the bulk of the gas Hope delivers. It is not probable that the investment of any two of these producers will bear the same ratio to their investments. The gas, however, all goes to the same use, has the same utilization value and the same ultimate price.

To regulate such an enterprise by undiscriminatingly transplanting any body of rate doctrine conceived and ***650** adapted to the ordinary utility business can serve the 'public interest' as the Natural Gas Act requires, if at all, only by accident. Mr. Justice Brandeis, the pioneer juristic advocate of the prudent investment theory for man-made utilities, never, so far as I am able to discover, proposed its application to a natural gas case. On the other hand, dissenting in Commonwealth of Pennsylvania v. West Virginia, he reviewed the problems of gas supply and said, 'In no other field of public service regulation is the controlling body confronted with factors so baffling as in the natural gas industry, and in none is continuous supervision and control required in so high a degree.' 262 U.S. 553, 621, 43 S.Ct. 658, 674, 67 L.Ed. 1117, 32 A.L.R. 300. If natural gas rates are intelligently to be regulated we must fit our legal principles to the economy of the industry and not try to fit the industry to our books.

As our decisions stand the Commission was justified in believing that it was required to proceed by the rate base method even as to gas in the field. For this reason the Court may not merely wash its hands of the method and rationale of rate making. The fact is that this Court, with no discussion of its fitness, simply transferred the rate base method to the natural gas industry. It happened in Newark Natural Gas & Fuel Co. v. City of Newark, Ohio, 1917, 242 U.S. 405, 37 S.Ct. 156, 157, 61 L.Ed. 393, Ann.Cas.1917B, 1025, in which the company wanted 25 cents per m.c.f., and under the Fourteenth Amendment challenged the reduction to 18 cents by ordinance. This Court sustained the reduction because the court below 'gave careful consideration to the questions of the value of the property * * * at the time of the inquiry,' and whether the rate 'would be sufficient to provide a fair return on the value of the property.' The Court said this method was 'based upon principles thoroughly established by repeated secisions of this court,' citing many cases, not one of which involved natural gas or a comparable wasting natural resource. Then came issues as to state power to ***651** regulate as affected by the commerce clause. Public Utilities Commission v. Landon, 1919, 249 U.S. 236, 39 S.Ct. 268, 63 L.Ed. 577; Pennsylvania Gas Co. v. Public Service Commission, 1920, 252 U.S. 23, 40 S.Ct. 279, 64 L.Ed. 434. These questions settled, the Court again was called upon in natural gas cases to consider state rate-making claimed to be invalid under the Fourteenth Amendment. United Fuel Gas Co. v. Railroad Commission of Kentucky, 1929, 278 U.S. 300, 49 S.Ct. 150, 73 L.Ed. 390; United Fuel Gas Company v. Public Service Commission of West Virginia, 1929, 278 U.S. 322, 49 S.Ct. 157, 73 L.Ed. 402. Then, as now, the differences were 'due ****311** chiefly to the difference in value ascribed by each to the gas rights and leaseholds.' 278 U.S. 300, 311, 49 S.Ct. 150, 153, 73 L.Ed. 390. No one seems to have questioned that the rate base method must be pursued and the controversy was at what rate base must be used. Later the 'value' of gas in the field was questioned in determining the amount a regulated company should be allowed to pay an affiliate therefor—a state determination also reviewed under the Fourteenth Amendment. Dayton Power & Light Co. v. Public Utilities Commission of Ohio, 1934, 292 U.S. 290, 54 S.Ct. 647, 78 L.Ed. 1267; Columbus Gas & Fuel Co. v. Public Utilities Commission of Ohio, 1934, 292 U.S. 398, 54 S.Ct. 763, 78 L.Ed. 1327, 91 A.L.R. 1403. In both cases, one of which sustained, and one of which struck down a fixed rate the Court assumed the rate base method, as the legal way of testing reasonableness of natural gas prices fixed by public authority, without examining its real relevancy to the inquiry.

Under the weight of such precedents we cannot expect the Commission to initiate economically intelligent methods of fixing gas prices. But the Court now faces a new plan of federal regulation based on the power to fix the price at which gas shall be allowed to move in interstate commerce. I should now consider whether these rules devised under the Fourteenth Amendment are the exclusive tests of a just and reasonable rate under the federal statute, inviting reargument directed to that point ***652** if necessary. As I see it now I would be prepared to hold that these rules do not apply to a natural gas case arising under the Natural Gas Act.

Such a holding would leave the Commission to fix the price of gas in the field as one would fix maximum prices of oil or milk or coal, or any other commodity. Such a price is not calculated to produce a fair return on the synthetic value of a rate base of any individual producer, and would not undertake to assure a fair return to any producer. The emphasis would shift from the producer to the product, which would be regulated with an eye to average or typical producing conditions in the field.

Such a price fixing process on economic lines would offer little temptation to the judiciary to become back seat drivers of the price fixing machine. The unfortunate effect of judicial intervention in this field is to divert the attention of those engaged in the process from what is economically wise to what is legally permissible. It is probable that price reductions would reach economically unwise and self-defeating limits before they would reach constitutional ones. Any constitutional problems growing out of price fixing are quite different than those that have heretofore been considered to inhere in rate making. A producer would have difficulty showing the invalidity of such a fixed price so long as he voluntarily continued to sell his product in interstate commerce. Should he withdraw and other authority be invoked to compel him to part with his property, a different problem would be presented.

Allowance in a rate to compensate for gas removed from gas lands, whether fixed as of point of production or as of point of delivery, probably best can be measured by a functional test applied to the whole industry. For good or ill we depend upon private enterprise to exploit these natural resources for public consumption. The function which an allowance for gas in the field should perform ***653** for society in such circumstances is to be enough and no more than enough to induce private enterprise completely and efficiently to utilize gas resources, to acquire for public service any available gas or gas rights and to deliver gas at a rate and for uses which will be in the future as well as in the present public interest.

The Court fears that 'if we are now to tell the Commission to fix the rates so as to discourage particular uses, we would indeed be injecting into a rate case a 'novel' doctrine * * *.' With due deference I suggest that there is nothing novel in the idea that any change in price of a service or commodity reacts to encourage or discourage its use. The question is not whether such consequences will or will not follow; the question is whether effects must be suffered blindly or may be intelligently selected, whether price control shall have targets at which it deliberately aims or shall be handled like a gun in the hands of one who does not know it is loaded.

We should recognize 'price' for what it is—a tool, a means, an expedient. In public ****312** hands it has much the same economic effects as in private hands. Hope knew that a concession in industrial price would tend to build up its volume of sales. It used price as an expedient to that end. The Commission makes another cut in that same price but the Court thinks we should ignore the effect that it will have on exhaustion of supply. The fact is that in natural gas regulation price must be used to reconcile the private property right society has permitted to vest in an important natural resource with the claims of society upon it—price must draw a balance between wealth and welfare.

To carry this into techniques of inquiry is the task of the Commissioner rather than of the judge, and it certainly is no task to be solved by mere bookkeeping but requires the best economic talent available. There would doubtless be inquiry into the price gas is bringing in the ***654** field, how far that price is established by arms' length bargaining and how far it may be influenced by agreements in restraint of trade or monopolistic influences. What must Hope really pay to get and to replace gas it delivers under this order? If it should get more or less than that for its own, how much and why? How far are such prices influenced by pipe line access to markets and if the consumers pay returns on the pipe lines how far should the increment they cause go to gas producers? East Ohio is itself a producer in Ohio. [44] What do Ohio authorities require Ohio consumers to pay for gas in the field? Perhaps these are reasons why the Federal Government should put West Virginia gas at lower or at higher rates. If so what are they? Should East Ohio be required to exploit its half million acres of unoperated reserve in Ohio before West Virginia resources shall be supplied on a devalued basis of which that State complains and for which she threatens measures of self keep? What is gas worth in terms of other fuels it displaces?

A price cannot be fixed without considering its effect on the production of gas. Is it an incentive to continue to exploit vast unoperated reserves? Is it conducive to deep drilling tests the result of which we may know only after trial? Will it induce bringing gas from afar to supplement or even to substitute for Appalachian gas? [45] Can it be had from distant fields as cheap or cheaper? If so, that competitive potentiality is certainly a relevant consideration. Wise regulation must also consider, as a private buyer would, what alternatives the producer has ***655** if the price is not acceptable. Hope has intrastate business and domestic and industrial customers. What can it do by way of diverting its supply to intrastate sales? What can it do by way of disposing of its operated or reserve acreage to industrial concerns or other buyers? What can West Virginia do by way of conservation laws, severance or other taxation, if the regulated rate offends? It must be borne in mind that while West Virginia was prohibited from giving her own inhabitants a priority that discriminated against interstate commerce, we have never yet held that a good faith conservation act, applicable to her own, as well as to others, is not valid. In considering alternatives, it must be noted that federal regulation is very incomplete, expressly excluding regulation of 'production or gathering of natural gas,' and that the only present way to get the gas seems to be to call it forth by price inducements. It is plain that there is a downward economic limit on a safe and wise price.

But there is nothing in the law which compels a commission to fix a price at that 'value' which a company might give to its product by taking advantage of scarcity, or monopoly of supply. The very purpose of fixing maximum prices is to take away from the seller his opportunity to get all that otherwise the market would award him for his goods. This is a constitutional use of the power to fix maximum prices, ****313** Block v. Hirsh, 256 U.S. 135, 41 S.Ct. 458, 65 L.Ed. 865, 16 A.L.R. 165; Marcus Brown Holding Co. v. Feldman, 256 U.S. 170, 41 S.Ct. 465, 65 L.Ed. 877; International Harvester Co. v. Kentucky, 234 U.S. 216, 34 S.Ct. 853, 58 L.Ed. 1284; Highland v. Russell Car & Snow Plow Co., 279 U.S. 253, 49 S.Ct. 314, 73 L.Ed. 688, just as the fixing of minimum prices of goods in interstate commerce is constitutional although it takes away from the buyer the advantage in bargaining which market conditions would give him. United States v. Darby, 312 U.S. 100, 657, 61 S.Ct. 451, 85 L.Ed. 609, 132 A.L.R. 1430; Mulford v. Smith, 307 U.S. 38, 59 S.Ct. 648, 83 L.Ed. 1092; United States v. Rock Royal Co-operative, Inc., 307 U.S. 533, 59 S.Ct. 993, 83 L.Ed. 1446; Sunshine Anthracite Coal Co. v. Adkins, 310 U.S. 381, 60 S.Ct. 907, 84 L.Ed. 1263. The Commission has power to fix ***656** a price that will be both maximum and minimum and it has the incidental right, and I think the duty, to choose the economic consequences it will promote or retard in production and also more importantly in consumption, to which I now turn.

If we assume that the reduction in company revenues is warranted we then come to the question of translating the allowed return into rates for consumers or classes of consumers. Here the Commission fixed a single rate for all gas delivered irrespective of its use despite the fact that Hope has established what amounts to two rates—a high one for domestic use and a lower one for industrial contracts. [46] The Commission can fix two prices for interstate gas as readily as one—a price for resale to domestic users and another for resale to industrial users. This is the pattern Hope itself has established in the very contracts over which the Commission is expressly given jurisdiction. Certainly the Act is broad enough to permit two prices to be fixed instead of one, if the concept of the 'public interest' is not unduly narrowed.

The Commission's concept of the public interest in natural gas cases which is carried today into the Court's opinion was first announced in the opinion of the minority in the Pipeline case. It enumerated only two 'phases of the public interest: (1) the investor interest; (2) the consumer interest,' which it emphasized to the exclusion of all others. 315 U.S. 575, 606, 62 S.Ct. 736, 753, 86 L.Ed. 1037. This will do well enough in dealing with railroads or utilities supplying manufactured gas, electric, power, a communications service or transportation, where utilization of facilities does not impair their future usefulness. Limitation of supply, however, brings into a natural gas case another phase of the public interest that to my mind overrides both the owner ***657** and the consumer of that interest. Both producers and industrial consumers have served their immediate private interests at the expense of the long-range public interest. The public interest, of course, requires stopping unjust enrichment of the owner.

But it also requires stopping unjust impoverishment of future generations. The public interest in the use by Hope's half million domestic consumers is quite a different one from the public interest in use by a baker's dozen of industries.

Prudent price fixing it seems to me must at the very threshold determine whether any part of an allowed return shall be permitted to be realized from sales of gas for resale for industrial use. Such use does tend to level out daily and seasonal peaks of domestic demand and to some extent permits a lower charge for domestic service. But is that a wise way of making gas cheaper when, in comparison with any substitute, gas is already a cheap fuel? The interstate sales contracts provide that at times when demand is so great that there is not enough gas to go around domestic users shall first be served. Should the operation of this preference await the day of actual shortage? Since the propriety of a preference seems conceded, should it not operate to prevent the coming of a shortage as well as to mitigate its effects? Should industrial use jeopardize tomorrow's service to householders any more than today's? If, however, it is decided to cheapen domestic use by resort to industrial sales, should they be limited to the few uses ****314** for which gas has special values or extend also to those who use it only because it is cheaper than competitive fuels?[47] And how much cheaper should industrial ***658** gas sell than domestic gas, and how much advantage should it have over competitive fuels? If industrial gas is to contribute at all to lowering domestic rates, should it not be made to contribute the very maximum of which it is capable, that is, should not its price be the highest at which the desired volume of sales can be realized?

If I were to answer I should say that the household rate should be the lowest that can be fixed under commercial conditions that will conserve the supply for that use. The lowest probable rate for that purpose is not likely to speed exhaustion much, for it still will be high enough to induce economy, and use for that purpose has more nearly reached the saturation point. On the other hand the demand for industrial gas at present rates already appears to be increasing. To lower further the industrial rate is merely further to subsidize industrial consumption and speed depletion. The impact of the flat reduction ***659** of rates ordered here admittedly will be to increase the industrial advantages of gas over competing fuels and to increase its use. I think this is not, and there is no finding by the Commission that it is, in the public interest.

There is no justification in this record for the present discrimination against domestic users of gas in favor of industrial users. It is one of the evils against which the Natural Gas Act was aimed by Congress and one of the evils complained of here by Cleveland and Akron. If Hope's revenues should be cut by some $3,600,000 the whole reduction is owing to domestic users. If it be considered wise to raise part of Hope's revenues by industrial purpose sales, the utmost possible revenue should be raised from the least consumption of gas. If competitive relationships to other fuels will permit, the industrial price should be substantially advanced, not for the benefit of the Company, but the increased revenues from the advance should be applied to reduce domestic rates. For in my opinion the 'public interest' requires that the great volume of gas now being put to uneconomic industrial use should either be saved for its more important future domestic use or the present domestic user should have the full benefit of its exchange value in reducing his present rates.

Of course the Commission's power directly to regulate does not extend to the fixing of rates at which the local company shall sell to consumers. Nor is such power required to accomplish the purpose. As already pointed out, the very contract the Commission is altering classifies the gas according to the purposes for which it is to be resold and provides differentials between the two classifications. It would only be necessary for the Commission to order ****315** that all gas supplied under paragraph (a) of Hope's contract with the East Ohio Company shall be ***660** at a stated price fixed to give to domestic service the entire reduction herein and any further reductions that may prove possible by increasing industrial rates. It might further provide that gas delivered under paragraph (b) of the contract for industrial purposes to those industrial customers Hope has approved in writing shall be at such other figure as might be found consistent with the public interest as herein defined. It is too late in the day to contend that the authority of a regulatory commission does not extend to a consideration of public interests which it may not directly regulate and a conditioning of its orders for their protection. Interstate Commerce Commission v. Railway Labor Executives Ass'n, 315 U.S. 373, 62 S.Ct. 717, 86 L.Ed. 904; United States v. Lowden, 308 U.S. 225, 60 S.Ct. 248, 84 L.Ed. 208.

Whether the Commission will assert its apparently broad statutory authorization over prices and discriminations is, of course, its own affair, not ours. It is entitled to its own notion of the 'public interest' and its judgment of policy must prevail. However, where there is ground for thinking that views of this Court may have constrained the Commission to accept the rate-base method of decision and a particular single formula as 'all important' for a rate base, it is appropriate to make clear the reasons why I, at least, would not be so understood. The Commission is free to face up realistically to the nature and peculiarity of the resources in its control, to foster their duration in fixing price, and to consider future interests in addition to those of investors and present consumers. If we return this case it may accept or decline the proffered freedom. This problem presents the Commission an unprecedented opportunity if it will boldly make sound economic considerations, instead of legal and accounting theories, the foundation of federal policy. I would return the case to the Commission and thereby be clearly quit of what now may appear to be some responsibility for perpetrating a shortsighted pattern of natural gas regulation.

Parallel Citations

51 P.U.R.(NS) 193, 64 S.Ct. 281, 88 L.Ed. 333

Footnotes

1 Hope produces about one-third of its annual gas requirements and purchases the rest under some 300 contracts.

2 These five companies are the East Ohio Gas Co., the Peoples Natural Gas Co., the River Gas Co., the Fayette County Gas Co., and the Manufacturers Light & Heat Co. The first three of these companies are, like Hope, subsidiaries of Standard Oil Co. (N.J.). East Ohio and River distribute gas in Ohio, the other three in Pennsylvania. Hope's approximate sales in m.c.f. for 1940 may be classified as follows:

Local West Virginia sales	11,000,000
East Ohio	40,000,000
Peoples	10,000,000
River	400,000
Fayette	860,000
Manufacturers	2,000,000

Local West Virginia

Hope's natural gas is processed by Hope Construction & Refining Co., an affiliate, for the extraction of gasoline and butane. Domestic Coke Corp., another affiliate, sells coke-oven gas to Hope for boiler fuel.

3 These required minimum reductions of 7¢ per m.c.f. from the 36.5¢ and 35.5¢ rates previously charged East Ohio and Peoples, respectively, and 3¢ per m.c.f. from the 31.5¢ rate previously charged Fayette and Manufacturers.

4 The book reserve for interstate plant amounted at the end of 1938 to about $18,000,000 more than the amount determined by the Commission as the proper reserve requirement. The Commission also noted that 'twice in the past the company has transferred amounts aggregating $7,500,000 from the depreciation and depletion reserve to surplus. When these latter adjustments are taken into account, the excess becomes $25,500,000, which has been exacted from the ratepayers over and above the amount required to cover the consumption of property in the service rendered and thus to keep the investment unimpaired.' 44 P.U.R.,N.S., at page 22.

5 That contention was based on the fact that 'every single dollar in the depreciation and depletion reserves' was taken 'from gross operating revenues whose only source was the amounts charged customers in the past for natural gas. It is, therefore, a fact that the depreciation and depletion reserves have been contributed by the customers and do not represent any investment by Hope.' Id., 44 P.U.R.,N.S., at page 40. And see Railroad Commission v. Cumberland Tel. & T. Co., 212 U.S. 414, 424, 425, 29 S.Ct. 357, 361, 362, 53 L.Ed. 577; 2 Bonbright, Valuation of Property (1937), p. 1139.

6 The Commission noted that the case was 'free from the usual complexities involved in the estimate of gas reserves because the geologists for the company and the Commission presented estimates of the remaining recoverable gas reserves which were about one per cent apart.' 44 P.U.R.,N.S., at pages 19, 20.

The Commission utilized the 'straight-line-basis' for determining the depreciation and depletion reserve requirements. It used estimates of the average service lives of the property by classes based in part on an inspection of the physical condition of the property. And studies were made of Hope's retirement experience and maintenance policies over the years. The average service lives of the various classes of property were converted into depreciation rates and then applied to the cost of the property to ascertain the portion of the cost which had expired in rendering the service.

The record in the present case shows that Hope is on the lookout for new sources of supply of natural gas and is contemplating an extension of its pipe line into Louisiana for that purpose. The Commission recognized in fixing the rates of depreciation that much material may be used again when various present sources of gas supply are exhausted, thus giving that property more than scrap value at the end of its present use.

7 See Uniform System of Accounts prescribed for Natural Gas Companies effective January 1, 1940, Account No. 332.1.

8 Sec. 6 of the Act comes the closest to supplying any definite criteria for rate making. It provides in subsection (a) that, 'The Commission may investigate the ascertain the actual legitimate cost of the property of every natural-gas company, the depreciation therein, and, when found necessary for rate-making purposes, other facts which bear on the determination of such cost or depreciation and the fair value of such property.' Subsection (b) provides that every natural-gas company on request shall file with the Commission a statement of the 'original cost' of its property and shall keep the Commission informed regarding the 'cost' of all additions, etc.

9 We recently stated that the meaning of the word 'value' is to be gathered 'from the purpose for which a valuation is being made. Thus the question in a valuation for rate making is how much a utility will be allowed to earn. The basic question in a valuation for reorganization purposes is how much the enterprise in all probability can earn.' Institutional Investors v. Chicago, M., St. P. & P.R. Co., 318 U.S. 523, 540, 63 S.Ct. 727, 738.

10 Chief Justice Hughes said in that case (292 U.S. at pages 168, 169, 54 S.Ct. at page 665, 78 L.Ed. 1182): 'If the predictions of service life were entirely accurate and retirements were made when and as these predictions were precisely fulfilled, the depreciation reserve would represent the consumption of capital, on a cost basis, according to the method which spreads that loss over the respective service periods. But if the amounts charged to operating expenses and credited to the account for depreciation reserve are excessive, to that extent subscribers for the telephone service are required to provide, in effect, capital contributions, not to make good losses incurred by the utility in the service rendered and thus to keep its investment unimpaired, but to secure additional plant and equipment upon which the utility expects a return.'

11 See Mr. Justice Brandeis (dissenting) in United Railways & Electric Co. v. West, 280 U.S. 234, 259—288, 50 S.Ct. 123, 128—138, 74 L.Ed. 390, for an extended analysis of the problem.

12 It should be noted that the Act provides no specific rule governing depletion and depreciation. Sec. 9(a) merely states that the Commission 'may from time to time ascertain and determine, and by order fix, the proper and adequate rates of depreciation and amortization of the several classes of property of each natural-gas company used or useful in the production, transportation, or sale of natural gas.'

13 See Simonton, The Nature of the Interest of the Grantee Under an Oil and Gas Lease (1918), 25 W.Va.L.Quar. 295.

14 West Penn Power Co. v. Board of Review, 112 W.Va. 442, 164 S.E. 862.

15 W.Va.Rev.Code of 1943, ch. 11. Art. 13, ss 2a, 3a.

16 West Virginia suggests as a possible solution (1) that a 'going concern value' of the company's tangible assets be included in the rate base and (2) that the fair market value of gas delivered to customers be added to the outlay for operating expenses and taxes.

17 S.Doc. 92, Pt. 84-A, ch. XII, Final Report, Federal Trade Commission to the Senate pursuant to S.Res.No. 83, 70th Cong., 1st Sess.

18 S.Doc. 92, Pt. 84-A, chs. XII, XIII, op. cit., supra, note 17.

19 See Hearings on H.R. 11662, Subcommittee of House Committee on Interstate & Foreign Commerce, 74th Cong., 2d Sess.; Hearings on H.R. 4008, House Committee on Interstate & Foreign Commerce, 75th Cong., 1st Sess.

20 The power to investigate and ascertain the 'actual legitimate cost' of property (s 6), the requirement as to books and records (s 8), control over rates of depreciation (s 9), the requirements for periodic and special reports (s 10), the broad powers of investigation (s 14) are among the chief powers supporting the rate making function.

21 Apart from the grandfather clause contained in s 7(c), there is the provision of s 7(f) that a natural gas company may enlarge or extend its facilities with the 'service area' determined by the Commission without any further authorization.

22 See P.L. 117, approved July 7, 1943, 57 Stat. 383 containing an 'Interstate Compact to Conserve Oil and Gas' between Oklahoma, Texas, New Mexico, Illinois, Colorado, and Kansas.

23 As we have pointed out, s 7(c) was amended by the Act of February 7, 1942, 56 Stat. 83, so as to require certificates of public convenience and necessity not only where the extensions were being made to markets in which natural gas was already being sold by another company but to other situations as well. Considerations of conservation entered into the proposal to give the Act that broader scope. H.Rep.No. 1290, 77th Cong. 1st Sess., pp. 2, 3. And see Annual Report, Federal Power Commission (1940) pp. 79, 80; Baum, The Federal Power Commission and State Utility Regulation (1942), p. 261.

The bill amending s 7(c) originally contained a subsection (h) reading as follows: 'Nothing contained in this section shall be construed to affect the authority of a State within which natural gas is produced to authorize or require the construction or extension of facilities for the transportation and sale of such gas within such State: Provided, however, That the Commission, after a hearing upon complaint or upon its own motion, may by order forbid any intrastate construction or extension by any natural-gas company which it shall find will prevent such company from rendering adequate service to its customers in interstate or foreign commerce in territory already being served.' See Hearings on H.R. 5249, House

Committee on Interstate & Foreign Commerce, 77th Cong., 1st Sess., pp. 7, 11, 21, 29, 32, 33. In explanation of its deletion the House Committee Report stated, pp. 4, 5: 'The increasingly important problems raised by the desire of several States to regulate the use of the natural gas produced therein in the interest of consumers within such States, as against the Federal power to regulate interstate commerce in the interest of both interstate and intrastate consumers, are deemed by the committee to warrant further intensive study and probably a more retailed and comprehensive plan for the handling thereof than that which would have been provided by the stricken subsection.'

24 We have noted that in the annual operating expenses of some $16,000.000 the Commission included West Virginia and federal taxes. And in the net increase of $421,160 over 1940 operating expenses allowed by the Commission was some $80,000 for increased West Virginia property taxes. The adequacy of these amounts has not been challenged here.

25 The Commission included in the aggregate annual operating expenses which it allowed some $8,500,000 for gas purchased. It also allowed about $1,400,000 for natural gas production and about $600,000 for exploration and development.

It is suggested, however, that the Commission in ascertaining the cost of Hope's natural gas production plant proceeded contrary to s 1(b) which provides that the Act shall not apply to 'the production or gathering of natural gas'. But such valuation, like the provisions for operating expenses, is essential to the rate-making function as customarily performed in this country. Cf. Smith, The Control of Power Rates in the United States and England (1932), 159 The Annals 101. Indeed s 14(b) of the Act gives the Commission the power to 'determine the propriety and reasonableness of the inclusion in operating expenses, capital, or surplus of all delay rentals or other forms of rental or compensation for unoperated lands and leases.'

26 See note 25, supra.

27 The Commission has expressed doubts over its power to fix rates on 'direct sales to industries' from interstate pipelines as distinguished from 'sales for resale to the industrial customers of distributing companies.' Annual Report, Federal Power Commission (1940), p. 11.

28 Sec. 1(b) of the Act provides: 'The provisions of this Act shall apply to the transportation of natural gas in interstate commerce, to the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or any other use, and to natural-gas companies engaged in such transportation or sale, but shall not apply to any other transportation or sale of natural gas or to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas.' And see s 2(6), defining a 'natural-gas company', and H.Rep.No. 709, supra, pp. 2, 3.

29 The wasting-asset characteristic of the industry was recognized prior to the Act as requiring the inclusion of a depletion allowance among operating expenses. See Columbus Gas & Fuel Co. v. Public Utilities Commission, 292 U.S. 398, 404, 405, 54 S.Ct. 763, 766, 767, 78 L.Ed. 1327, 91 A.L.R. 1403. But no such theory of rate-making for natural gas companies as is now suggested emerged from the cases arising during the earlier period of regulation.

30 The Commission has been alert to the problems of conservation in its administration of the Act. It has indeed suggested that it might be wise to restrict the use of natural gas 'by functions rather than by areas.' Annual Report (1940) p. 79.

The Commission stated in that connection that natural gas was particularly adapted to certain industrial uses. But it added that the general use of such gas 'under boilers for the production of steam' is 'under most circumstances of very questionable social economy.' Ibid.

31 The argument is that s 4(a) makes 'unlawful' the charging of any rate that is not just and reasonable. And s 14(a) gives the Commission power to investigate any matter 'which it may find necessary or proper in order to determine whether any person has violated' any provision of the Act. Moreover, s 5(b) gives the Commission power to investigate and determine the cost of production or transportation of natural gas in cases where it has 'no authority to establish a rate governing the transportation or sale of such natural gas.' And s 17(c) directs the Commission to 'make available to the several State commissions such information and reports as may be of assistance in State regulation of natural-gas companies.' For a discussion of these points by the Commission see 44 P.U.R.,N.S., at pages 34, 35.

1 Natural Gas Act, s 4(a), 52 Stat. 821, 822, 15 U.S.C. s 717c(a), 15 U.S.C.A. s 717c(a).

2 52 Stat. 821, 824, 15 U.S.C. s 717e, 15 U.S.C.A. s 717e:

'(a) The Commission may investigate and ascertain the actual legitimate cost of the property of every natural-gas company, the depreciation therein, and, when found necessary for rate-making purposes, other facts which bear on the determination of such cost or depreciation and the fair value of such property.

'(b) Every natural-gas company upon request shall file with the Commission an inventory of all or any part of its property and a statement of the original cost thereof, and shall keep the Commission informed regarding the cost of all additions, betterments, extensions, and new construction.'

3 'Reproduction cost' has been variously defined, but for rate making purposes the most useful sense seems to be, the minimum amount necessary to create at the time of the inquiry a modern plant capable of rendering equivalent service. See I Bonbright, Valuation of Property (1937) 152. Reproduction cost as the cost of building a replica of an obsolescent plant is not of real significance.

'Prudent investment' is not defined by the Court. It may mean the sum originally put in the enterprise, either with or without additional amounts from excess earnings reinvested in the business.

4 It is of no more than bookkeeping significance whether the Commission allows a rate of return commensurate with the risk of the original investment or the lower rate based on current risk and a capitalization reflecting the established earning power of a successful company and the probable cost of duplicating its services. Cf. American T. & T. Co. v. United States, 299 U.S. 232, 57 S.Ct. 170, 81 L.Ed. 142. But the latter is the traditional method.

1 315 U.S. 575, 62 S.Ct. 736, 86 L.Ed. 1037.

2 Judge Dobie, dissenting below, pointed out that the majority opinion in the Pipeline case 'contains no express discussion of the Prudent Investment Theory' and that the concurring opinion contained a clear one, and said, 'It is difficult for me to believe that the majority of the Supreme Court, believing otherwise, would leave such a statement unchallenged.' (134 F.2d 287, 312.) The fact that two other Justices had as matter of record in our books long opposed the reproduction cost theory of rate bases and had commented favorably on the prudent investment theory may have influenced that conclusion. See opinion of Mr. Justice Frankfurter in Driscoll v. Edison Light & Power Co., 307 U.S. 104, 122, 59 S.Ct. 715, 724, 83 L.Ed. 1134, and my brief as Solicitor General in that case. It should be noted, however, that these statements were made, not in a natural gas case, but in an electric power case—a very important distinction, as I shall try to make plain.

3 Natural gas from the Appalachian field averages about 1050 to 1150 B.T.U. content, while by-product manufactured gas is about 530 to 540. Moody's Manual of Public Utilities (1943) 1350; Youngberg, Natural Gas (1930) 7.

4 Sen.Rep. No. 1162, 75th Cong., 1st Sess., 2.

5 Arnold and Kemnitzer, Petroleum in the United States and Possessions (1931) 78.

6 Id. at 62-63.

7 Id. at 61.

8 At Fredonia, New York, in 1821, natural gas was conveyed from a shallow well to some thirty people. The lighthouse at Barcelona Harbor, near what is now Westfield, New York, was at about that time and for many years afterward lighted by gas that issued from a crevice. Report on Utility Corporations by Federal Trade Commission, Sen.Doc. 92, Pt. 84-A, 70th Cong., 1st Sess., 8-9.

9 In that year Pennsylvania enacted 'An Act to provide for the incorporation and regulation of natural gas companies.' Penn.Laws 1885, No. 32, 15 P.S. s 1981 et seq.

10 See Steptoe and Hoffheimer's Memorandum for Governor Cornwell of West Virginia (1917) 25 West Virginia Law Quarterly 257; see also Report on Utility Corporations by Federal Trade Commission, Sen.Doc. No. 92, Pt. 84-A, 70th Cong., 1st Sess.

11 Arnold and Kemnitzer, Petroleum in the United States and Possessions (1931) 73.

12 Id. at 63.

13 Id. at 64.

14 See Report on Utility Corporations by Federal Trade Commission, Sen.Doc. No. 92, Pt. 84-A, 70th Cong., 1st Sess.

15 Commonwealth of Pennsylvania v. West Virginia, 262 U.S. 553, 43 S.Ct. 658, 67 L.Ed. 1117, 32 A.L.R. 300. For conditions there which provoked this legislation, see 25 West Virginia Law Quarterly 257.

16 People ex rel. Pavilion Natural Gas Co. v. Public Service Commission, 188 App.Div. 36, 176 N.Y.S. 163.

17 Village of Falconer v. Pennsylvania Gas Company, 17 State Department Reports, N.Y., 407.

18 See, for example, Public Service Commission v. Iroquois Natural Gas Co., 108 Misc. 696, 178 N.Y.S. 24; Park Abbott Realty Co. v. Iroquois Natural Gas Co., 102 Misc. 266, 168 N.Y.S. 673; Public Service Commission v. Iroquois Natural Gas Co., 189 App.Div. 545, 179 N.Y.S. 230.

19 People ex rel. Pennsylvania Gas Co. v. Public Service Commission, 196 App.Div. 514, 189 N.Y.S. 478.

20 East Ohio Gas Co. v. Akron, 81 Ohio St. 33, 90 N.E. 40, 26 L.R.A., N.S., 92, 18 Ann.Cas. 332; Village of New-comerstown v. Consolidated Gas Co., 100 Ohio St. 494, 127 N.E. 414; Gress v. Village of Ft. Laramie, 100 Ohio St. 35, 125 N.E. 112, 8 A.L.R. 242; City of Jamestown v. Pennsylvania Gas Co., D.C., 263 F. 437; Id., D.C., 264 F. 1009. See, also, United Fuel Gas Co. v. Railroad Commission, 278 U.S. 300, 308, 49 S.Ct. 150, 152, 73 L.Ed. 390.

21 The New York Public Service Commission said: 'While the transportation of natural gas through pipe lines from one state to another state is interstate commerce * * *, Congress has not taken over the regulation of that particular industry. Indeed,

it has expressly excepted it from the operation of the Interstate Commerce Commissions Law (Interstate Commerce Commissions Law, section 1). It is quite clear, therefore, that this Commission can not require a Pennsylvania corporation producing gas in Pennsylvania to transport it and deliver it in the State of New York, and that the Interstate Commerce Commission is likewise powerless. If there exists such a power, and it seems that there does, it is a power vested in Congress and by it not yet exercised. There is no available source of supply for the Crystal City Company at present except through purchasing from the Porter Gas Company. It is possible that this Commission might fix a price at which the Potter Gas Company should sell if it sold at all, but as the Commission can not require it to supply gas in the State of New York, the exercise of such a power to fix the price, if such power exists, would merely say, sell at this price or keep out of the State.' Lane v. Crystal City Gas Co., 8 New York Public Service Comm.Reports, Second District, 210, 212.

22 Proclamation by the President of September 16, 1918; Rules and Regulations of H. A. Garfield, Fuel Administrator, September 24, 1918.

23 For example, the Iroquois Gas Corporation which formerly served Buffalo, New York, with natural gas ranging from 1050 to 1150 b.t.u. per cu. ft., now mixes a by-product gas of between 530 and 540 b.t.u. in proportions to provide a mixed gas of about 900 b.t.u. per cu. ft. For space heating or water heating its charges range from 65 cents for the first m.c.f. per month to 55 cents for all above 25 m.c.f. per month. Moody's Manual of Public Utilities (1943) 1350.

24 The United States Fuel Administration made the following cooking value comparisons, based on tests made in the Department of Home Economics of Ohio State University:

Natural gas at 1.12 per M. is equivalent to coal at $6.50 per ton.
Natural gas at 2.00 per M. is equivalent to gasoline at 27¢ per gal.
Natural gas at 2.20 per M. is equivalent to electricity at 3¢ per k.w.h.
Natural gas at 2.40 per M. is equivalent to coal oil at 15¢ per gal.
Use and Conservation of Natural Gas, issued by U.S. Fuel Administration (1918) 5.

25 See Brief on Behalf jof Legislation Imposing an Excise Tax on Natural Gas, submitted to N.R.A. by the United Mine Workers of America and the National Coal Association.

26 Brief of National Gas Association and United Mine Workers, supra, note 26, pp. 35, 36, compiled from Bureau of Mines Reports.

27 From the source quoted in the preceding note the spread elsewhere is shown to be:

State	Industrial	Domestic
Illinois...	29.2	1.678
Louisiana..	10.4	59.7
Oklahoma...	11.2	41.5
Texas...	13.1	59.7
Alabama...	17.8	1.227
Georgia..	22.9	1.043

28 In Corning, New York, rates were initiated by the Crystal City Gas Company as follows: 70¢ for the first 5,000 cu. ft. per month; 80¢ from 5,000 to 12,000; $1 for all over 12,000. The Public Service Commission rejected these rates and fixed a flat rate of 58¢ per m.c.f. Lane v. Crystal City Gas Co., 8 New York Public Service Comm. Reports, Second District, 210. The Pennsylvania Gas Company (National Fuel Gas Company group) also attempted a sliding scale rate for New York consumers, net per month as follows: First 5,000 feet, 35¢; second 5,000 feet, 45¢; third 5,000 feet, 50¢; all above 15,000, 55¢. This was eventually abandoned, however. The company's present scale in Pennsylvania appears to be reversed to the following net monthly rate; first 3 m.c.f., 75¢; next 4 m.c.f., 60¢; next 8 m.c.f., 55¢; over 15 m.c.f., 50¢ . Moody's Manual of Public Utilities (1943) 1350. In New York it now serves a mixed gas.

For a study of effect of sliding scale rates in reducing consumption see 11 Proceedings of Natural Gas Association of America (1919) 287.

29 See Report on Utility Corporations by Federal Trade Commission, Sen. Doc. 92, Pt. 84-A, 70th Cong., 1st Sess.

30 Four holding company systems control over 55 per cent of all natural gas transmission lines in the United States. They are Columbia Gas and Electric Corporation, Cities Service Co., Electric Bond and Share Co., and Standard Oil Co. of New Jersey. Columbia alone controls nearly 25 per cent, and fifteen companies account for over 80 per cent of the total. Report on Utility Corporations by Federal Trade Commission, Sen. Doc. 92, Pt. 84-A, 70th Cong., 1st Sess., 28.

In 1915, so it was reported to the Governor of West Virginia, 87 per cent of the total gas production of that state was under control of eight companies. Steptoe and Hoffheimer, Legislative Regulation of Natural Gas Supply in West Virginia, 17 West Virginia Law Quarterly 257, 260. Of these, three were subsidiaries of the Columbia system and others were subsidiaries of larger systems. In view of inter-system sales and interlocking interests it may be doubted whether there is much real competition among these companies.

31 This pattern with its effects on local regulatory efforts will be observed in our decisions. See United Fuel Gas Co. v. Railroad Commission, 278 U.S. 300, 49 S.Ct. 150, 73 L.Ed. 390; United Fuel Gas Co. v. Public Service Commission, 278 U.S. 322, 49 S.Ct. 157, 73 L.Ed. 402; Dayton Power & Light v. Public Utilities Commission, 292 U.S. 290, 54 S.Ct. 647, 78 L.Ed. 1267; Columbus Gas & Fuel Co. v. Public Utilities Commission, 292 U.S. 398, 54 S.Ct. 763, 78 L.Ed. 1327, 91 A.L.R. 1403, and the present case.

32 15 U.S.C. s 717(a), 15 U.S.C.A. s 717(a). (Italics supplied throughout this paragraph.)

33 s 7(c), 52 Stat. 825, 15 U.S.C.A. s 717f(c).

34 15 U.S.C. s 717f, 15 U.S.C.A. s 717f.

35 Id., s 717c(e).

36 Id., s 717c(b).

37 Id., s 717d(a).

38 Sen. Rep. No. 1162, 75th Cong., 1st Sess. 2.

39 The list of East Ohio Gas Company's special industrial contracts thus expressly under Hope's control and their demands are as follows:

40 To make a fetish of mere accounting is to shield from examination the deeper causes, forces, movements, and conditions which should govern rates. Even as a recording of current transactions, bookkeeping is hardly an exact science. As a representation of the condition and trend of a business, it uses symbols of certainty to express values that actually are in constant flux. It may be said that in commercial or investment banking or any business extending credit success depends on knowing what not to believe in accounting. Few concerns go into bankruptcy or reorganization whose books do not show them solvent and often even profitable. If one cannot rely on accountancy accurately to disclose past or current conditions of a business, the fallacy of using it as a sole guide to future price policy ought to be apparent. However, our quest for certitude is so ardent that we pay an irrational reverence to a technique which uses symbols of certainty, even though experience again and again warns us that they are delusive. Few writers have ventured to challenge this American idolatry, but see Hamilton, Cost as a standard for Price, 4 Law and Contemporary Problems 321, 323-25. He observes that 'As the apostle would put it, accountancy is all things to all men. * * * Its purpose determines the character of a system of accounts.' He analyzes the hypothetical character of accounting and says 'It was no eternal mold for pecuniary verities handed down from on high. It was—like logic or algebra, or the device of analogy in the law—an ingenious contrivance of the human mind to serve a limited and practical purpose.' 'Accountancy is far from being a pecuniary expression of all that is industrial reality. It is an instrument, highly selective in its application, in the service of the institution of money making.' As to capital account he observes 'In an enterprise in lusty competition with others of its kind, survival is the thing and the system of accounts has its focus in solvency. * * * Accordingly depreciation, obsolescence, and other factors which carry no immediate threat are matters of lesser concern and the capital account is likely to be regarded as a secondary phenomenon. * * * But in an enterprise, such as a public utility, where continued survival seems assured, solvency is likely to be taken for granted. * * * A persistent and ingenious attention is likely to be directed not so much to securing the upkeep of the physical property as to making it certain that capitalization fails in not one whit to give full recognition to every item that should go into the account.'

41 See 2 Bonbright, Valuation of Property (1937) 1112.

42 Bonbright says, '* * * the vice of traditional law lies, not in its adoption of excessively rigid concepts of value and rules of valuation, but rather in its tendency to permit shifts in meaning that are inept, or else that are ill-defined because the judges that make them will not openly admit that they are doing so.' Id., 1170.

43 'The attempt to regulate rates by reference to a periodic or occasional reappraisal of the properties has now been tested long enough to confirm the worst fears of its critics. Unless its place is taken by some more promising scheme of rate control, the days of private ownership under government regulation may be numbered.' 2 Bonbright, Valuation of Property (1937) 1190.

44 East Ohio itself owns natural gas rights in 550,600 acres, 518,526 of which are reserved and 32,074 operated, by 375 wells. Moody's Manual of Public Utilities (1943) 5.

45 Hope has asked a certificate of convenience and necessity to lay 1140 miles of 22-inch pipeline from Hugoton gas fields in southwest Kansas to West Virginia to carry 285 million cu. ft. of natural gas per day. The cost was estimated at $51,000,000. Moody's Manual of Public Utilities (1943) 1760.

46 I find little information as to the rates for industries in the record and none at all in such usual sources as Moody's Manual.

47 The Federal Power Commission has touched upon the problem of conservation in connection with an application for a certificate permitting construction of a 1500-mile pipeline from southern Texas to New York City and says: ‘The Natural Gas Act as presently drafted does not enable the Commission to treat fully the serious implications of such a problem. The question should be raised as to whether the proposed use of natural gas would not result in displacing a less valuable fuel and create hardships in the industry already supplying the market, while at the same time rapidly depleting the country's natural-gas reserves. Although, for a period of perhaps 20 years, the natural gas could be so priced as to appear to offer an apparent saving in fuel costs, this would mean simply that social costs which must eventually be paid had been ignored. ‘Careful study of the entire problem may lead to the conclusion that use of natural gas should be restricted by functions rather than by areas. Thus, it is especially adapted to space and water heating in urban homes and other buildings and to the various industrial heat processes which require concentration of heat, flexibility of control, and uniformity of results. Industrial uses to which it appears particularly adapted include the treating and annealing of metals, the operation of kilns in the ceramic, cement, and lime industries, the manufacture of glass in its various forms, and use as a raw material in the chemical industry. General use of natural gas under boilers for the production of steam is, however, under most circumstances of very questionable social economy.’ Twentieth Annual Report of the Federal Power Commission (1940) 79.

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Supreme Court of the United States
BLUEFIELD WATERWORKS & IMPROVEMENT CO.
v.
PUBLIC SERVICE COMMISSION OF WEST VIRGINIA et al.
No. 256.

Argued January 22, 1923.
Decided June 11, 1923.

In Error to the Supreme Court of Appeals of West Virginia.

Proceedings by the Bluefield Waterworks & Improvement Company against the Public Service Commission of the State of West Virginia and others to suspend and set aside an order of the Commission fixing rates. From a judgment of the Supreme Court of West Virginia, dismissing the petition, and denying the relief (89 W. Va. 736, 110 S. E. 205), the Waterworks Company bring error. Reversed.

West Headnotes

Constitutional Law 92 298(1.5)

92 Constitutional Law
92XII Due Process of Law
92k298 Regulation of Charges and Prices
92k298(1.5) k. Public Utilities in General. Most Cited Cases
Rates which are not sufficient to yield a reasonable return on the value of the property used in public service at the time it is being so used to render the service are unjust, unreasonable, and confiscatory, and their enforcement deprives the public utility company of its property, in violation of the Fourteenth Amendment of the Constitution.

Constitutional Law 92 298(3)

92 Constitutional Law
92XII Due Process of Law
92k298 Regulation of Charges and Prices
92k298(3) k. Water and Irrigation Companies. Most Cited Cases
Under the due process clause of the Fourteenth Amendment of the Constitution, U.S.C.A., a waterworks company is entitled to the independent judgment of the court as to both law and facts, where the question is whether the rates fixed by a public service commission are confiscatory.

Waters and Water Courses 405 203(10)

405 Waters and Water Courses
405IX Public Water Supply
405IX(A) Domestic and Municipal Purposes
405k203 Water Rents and Other Charges
405k203(10) k. Reasonableness of Charges. Most Cited Cases
It was error for a state public service commission, in arriving at the value of the property used in public service, for the purpose of fixing the rates, to fail to give proper weight to the greatly increased cost of construction since the war.

Waters and Water Courses 405 203(10)

405 Waters and Water Courses
405IX Public Water Supply
405IX(A) Domestic and Municipal Purposes
405k203 Water Rents and Other Charges
405k203(10) k. Reasonableness of Charges. Most Cited Cases
A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties, but it has no constitutional right to such profits as are realized or anticipated in highly profitable enterprises or speculative ventures.

Waters and Water Courses 405 203(10)

405 Waters and Water Courses
405IX Public Water Supply
405IX(A) Domestic and Municipal Purposes
405k203 Water Rents and Other Charges
405k203(10) k. Reasonableness

(Cite as: P.U.R. 1923D 11, 43 S.Ct. 675)

of Charges. Most Cited Cases
Since the investors take into account the result of past operations as well as present rates in determining whether they will invest, a waterworks company which had been earning a low rate of returns through a long period up to the time of the inquiry is entitled to return of more than 6 per cent. on the value of its property used in the public service, in order to justly compensate it for the use of its property.

Federal Courts 170B 504.1

170B Federal Courts
170BVII Supreme Court
170BVII(E) Review of Decisions of State Courts
170Bk504 Nature of Decisions or Questions Involved
170Bk504.1 k. In General. Most Cited Cases
(Formerly 106k394(6))
A proceeding in a state court attacking an order of a public service commission fixing rates, on the ground that the rates were confiscatory and the order void under the federal Constitution, is one where there is drawn in question the validity of authority exercised under the state, on the ground of repugnancy to the federal Constitution, and therefore is reviewable by writ of error.

****675 *680** Messrs. Alfred G. Fox and Jos. M. Sanders, both of Bluefield, W. Va., for plaintiff in error.
Mr. Russell S. Ritz, of Bluefield, W. Va., for defendants in error.

***683** Mr. Justice BUTLER delivered the opinion of the Court.
Plaintiff in error is a corporation furnishing water to the city of Bluefield, W. Va., ****676** and its inhabitants. September 27, 1920, the Public Service Commission of the state, being authorized by statute to fix just and reasonable rates, made its order prescribing rates. In accordance with the laws of the state (section 16, c. 15-O, Code of West Virginia [sec. 651]), the company instituted proceedings in the Supreme Court of Appeals to suspend and set aside the order. The petition alleges that the order is repugnant to the Fourteenth Amendment, and deprives the company of its property without just compensation and without due process of law, and denies it equal protection of the laws. A final judgment was entered, denying the company relief and dismissing its petition. The case is here on writ of error.

[1] 1. The city moves to dismiss the writ of error for the reason, as it asserts, that there was not drawn in question the validity of a statute or an authority exercised under the state, on the ground of repugnancy to the federal Constitution.

The validity of the order prescribing the rates was directly challenged on constitutional grounds, and it was held valid by the highest court of the state. The prescribing of rates is a legislative act. The commission is an instrumentality of the state, exercising delegated powers. Its order is of the same force as would be a like enactment by the Legislature. If, as alleged, the prescribed rates are confiscatory, the order is void. Plaintiff in error is entitled to bring the case here on writ of error and to have that question decided by this court. The motion to dismiss will be denied. See ***684**Oklahoma Natural Gas Co. v. Russell, 261 U. S. 290, 43 Sup. Ct. 353, 67 L. Ed. 659, decided March 5, 1923, and cases cited; also Ohio Valley Co. v. Ben Avon Borough, 253 U. S. 287, 40 Sup. Ct. 527, 64 L. Ed. 908.

2. The commission fixed $460,000 as the amount on which the company is entitled to a return. It found that under existing rates, assuming some increase of business, gross earnings for 1921 would be $80,000 and operating expenses $53,000 leaving $27,000, the equivalent of 5.87 per cent., or 3.87 per cent. after deducting 2 per cent. allowed for depreciation. It held existing rates insufficient to the extent of 10,000. Its order allowed the company to add 16 per cent. to all bills, excepting those for public and private fire protection. The total of the bills so to be increased amounted to $64,000; that is, 80 per cent. of the revenue was authorized to be increased 16 per cent., equal to an increase of 12.8 per cent. on the total, amounting to $10,240.

As to value: The company claims that the value of the property is greatly in excess of $460,000. Reference to the evidence is necessary. There was submitted to the commission evidence of value which it summarized substantially as follows:

a. Estimate by company's engineer

(Cite as: P.U.R. 1923D 11, 43 S.Ct. 675)

	on. basis of reproduction new, less. depreciation, at prewar prices.	$ 624,548 00
b.	Estimate by company's engineer on. basis of reproduction new, less. depreciation, at 1920 prices.	1,194,663 00
c.	Testimony of company's engineer. fixing present fair value for rate. making purposes.	900,000 00
d.	Estimate by commissioner's engineer on. basis of reproduction new, less. depreciation at 1915 prices, plus. additions since December 31, 1915, at. actual cost, excluding Bluefield. Valley waterworks, water rights,. and going value.	397,964 38
e.	Report of commission's statistician. showing investment cost less. depreciation.	365,445 13
f.	Commission's valuation, as fixed in. case No. 368 ($360,000), plus gross. additions to capital since made. ($92,520.53).	452,520 53

***685** It was shown that the prices prevailing in 1920 were nearly double those in 1915 and pre-war time. The company did not claim value as high as its estimate of cost of construction in 1920. Its valuation engineer testified that in his opinion the value of the property was $900,000-a figure between the cost of construction in 1920, less depreciation, and the cost of construction in 1915 and before the war, less depreciation.

The commission's application of the evidence may be stated briefly as follows:

As to ‘a,’ supra: The commission deducted $204,000 from the estimate (details printed in the margin), [FN1] leaving approximately $421,000, which it contrasted with the estimate of its own engineer, $397,964.38 (see ‘d,’ supra). It found that there should be included $25,000 for the Bluefield Valley waterworks plant in Virginia, 10 per cent. for going value, and $10,000 for working capital. If these be added to $421,000, there results $500,600. This may be compared with the commission's final figure, $460,000.

FN1

Difference in depreciation allowed.	$ 49,000
Preliminary organization and development. cost.	14,500
Bluefield Valley waterworks plant.	25,000
Water rights.	50,000
Excess overhead costs.	39,000
Paving over mains.	28,500
	$204,000

(Cite as: P.U.R. 1923D 11, 43 S.Ct. 675)

***686** As to 'b' and 'c,' supra: These were given no weight by the commission in arriving at its final figure, $460,000. It said:

'Applicant's plant was originally constructed more than twenty years ago, and has been added to from time to time as the progress and development of the community required. For this reason, it would be unfair to its consumers to use as a basis for present fair value the abnormal prices prevailing during the recent war period; but, when, as in this case, a part of the plant has been constructed or added to during that period, in fairness to the applicant, consideration must be given to the cost of such expenditures made to meet the demands of the public.'

****677** As to 'd,' supra: The commission, taking $400,000 (round figures), added $25,000 for Bluefield Valley waterworks plant in Virginia, 10 per cent. for going value, and $10,000 for working capital, making $477,500. This may be compared with its final figure, $460,000.

As to 'e,' supra: The commission, on the report of its statistician, found gross investment to be $500,402.53. Its engineer, applying the straight line method, found 19 per cent. depreciation. It applied 81 per cent. to gross investment and added 10 per cent. for going value and $10,000 for working capital, producing $455,500. FN2 This may be compared with its final figure, $460,000.

FN2 As to 'e': $365,445.13 represents investment cost less depreciation. The gross investment was found to be $500,402.53, indicating a deduction on account of depreciation of $134,957.40, about 27 per cent., as against 19 per cent. found by the commission's engineer.

As to 'f,' supra: It is necessary briefly to explain how this figure, $452,520.53, was arrived at. Case No. 368 was a proceeding initiated by the application of the company for higher rates, April 24, 1915. The commission made a valuation as of January 1, 1915. There were presented two estimates of reproduction cost less depreciation, one by a valuation engineer engaged by the company, ***687** and the other by a valuation engineer engaged by the city, both 'using the same method.' An inventory made by the company's engineer was accepted as correct by the city and by the commission. The method 'was that generally employed by courts and commissions in arriving at the value of public utility properties under this method.' and in both estimates 'five year average unit prices' were applied. The estimate of the company's engineer was $540,000 and of the city's engineer, $392,000. The principal differences as given by the commission are shown in the margin. FN3 The commission disregarded both estimates and arrived at $360,000. It held that the best basis of valuation was the net investment, i. e., the total cost of the property less depreciation. It said:

'The books of the company show a total gross investment, since its organization, of $407,882, and that there has been charged off for depreciation from year to year the total sum of $83,445, leaving a net investment of

FN3

		Company Engineer.	City Engineer.
1.	Preliminary costs.	$14,455	$1,000
2.	Water rights.	50,000	Nothing
3.	Cutting pavements over. mains.	27,744	233
4.	Pipe lines from gravity. springs.	22,072	15,442
5.	Laying cast iron street. mains.	19,252	15,212
6.	Reproducing Ada springs.	18,558	13,027
7.	Superintendence and. engineering.	20,515	13,621
8.	General contingent cost.	16,415	5,448
		$189,011	$63,983

(Cite as: P.U.R. 1923D 11, 43 S.Ct. 675)

$324,427. * * * From an examination of the books * * * it appears that the records of the company have been remarkably well kept and preserved. It therefore seems that, when a plant is developed under these conditions, the net investment, which, of course, means the total gross investment less depreciation, is the very best basis of valuation for rate making purposes and that the other methods above referred to should ***688** be used only when it is impossible to arrive at the true investment. Therefore, after making due allowance for capital necessary for the conduct of the business and considering the plant as a going concern, it is the opinion of the commission that the fair value for the purpose of determining reasonable and just rates in this case of the property of the applicant company, used by it in the public service of supplying water to the city of Bluefield and its citizens, is the sum of $360,000, which sum is hereby fixed and determined by the commission to be the fair present value for the said purpose of determining the reasonable and just rates in this case.'

In its report in No. 368, the commission did not indicate the amounts respectively allowed for going value or working capital. If 10 per cent. be added for the former, and $10,000 for the latter (as fixed by the commission in the present case), there is produced $366,870, to be compared with $360,000, found by the commission in its valuation as of January 1, 1915. To this it added $92,520.53, expended since, producing $452,520.53. This may be compared with its final figure, $460,000.

The state Supreme Court of Appeals holds that the valuing of the property of a public utility corporation and prescribing rates are purely legislative acts, not subject to judicial review, except in so far as may be necessary to determine whether such rates are void on constitutional or other grounds, and that findings of fact by the commission based on evidence to support them will not be reviewed by the court. City of Bluefield v. Waterworks, 81 W. Va. 201, 204, 94 S. E. 121; Coal & Coke Co. v. Public Service Commission, 84 W. Va. 662, 678, 100 S. E. 557, 7 A. L. R. 108; Charleston v. Public Service Commission, 86 W. Va. 536, 103 S. E. 673.

In this case (89 W. Va. 736, 738, 110 S. E. 205, 206) it said:
'From the written opinion of the commission we find that it ascertained the value of the petitioner's property for rate making [then quoting the commission] 'after ***689** maturely and carefully considering the various methods presented for the ascertainment of fair value and giving such weight as seems proper to every element involved and all the facts and circumstances disclosed by the record.''

[2] [3] The record clearly shows that the commission, in arriving at its final figure, did not accord proper, if any, weight to the greatly enhanced costs of construction in 1920 over those prevailing about 1915 and before the war, as established by uncontradicted ****678** evidence; and the company's detailed estimated cost of reproduction new, less depreciation, at 1920 prices, appears to have been wholly disregarded. This was erroneous. Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri, 262 U. S. 276, 43 Sup. Ct. 544, 67 L. Ed. 981, decided May 21, 1923. Plaintiff in error is entitled under the due process clause of the Fourteenth Amendment to the independent judgment of the court as to both law and facts. Ohio Valley Co. v. Ben Avon Borough, 253 U. S. 287, 289, 40 Sup. Ct. 527, 64 L. Ed. 908, and cases cited.

We quote further from the court's opinion (89 W. Va. 739, 740, 110 S. E. 206):
'In our opinion the commission was justified by the law and by the facts in finding as a basis for rate making the sum of $460,000.00. * * * In our case of Coal & Coke Ry. Co. v. Conley, 67 W. Va. 129, it is said: 'It seems to be generally held that, in the absence of peculiar and extraordinary conditions, such as a more costly plant than the public service of the community requires, or the erection of a plant at an actual, though extravagant, cost, or the purchase of one at an exorbitant or inflated price, the actual amount of money invested is to be taken as the basis, and upon this a return must be allowed equivalent to that which is ordinarily received in the locality in which the business is done, upon capital invested in similar enterprises. In addition to this, consideration must be given to the nature of the investment, a higher rate ***690** being regarded as justified by the risk incident to a hazardous investment.'
'That the original cost considered in connection with the history and growth of the utility and the value of the services rendered constitute the principal elements to be considered in connection with rate making, seems to be supported by nearly all the authorities.'

[4] The question in the case is whether the rates prescribed in the commission's order are confiscatory and therefore beyond legislative power. Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the service are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment. This is so well settled by numerous decisions of this court that citation of the cases is scarcely necessary:

(Cite as: P.U.R. 1923D 11, 43 S.Ct. 675)

'What the company is entitled to ask is a fair return upon the value of that which it employs for the public convenience.' Smyth v. Ames (1898) 169 U. S. 467, 547, 18 Sup. Ct. 418, 434 (42 L. Ed. 819).

'There must be a fair return upon the reasonable value of the property at the time it is being used for the public. * * * And we concur with the court below in holding that the value of the property is to be determined as of the time when the inquiry is made regarding the rates. If the property, which legally enters into the consideration of the question of rates, has increased in value since it was acquired, the company is entitled to the benefit of such increase.' Willcox v. Consolidated Gas Co. (1909) 212 U. S. 19, 41, 52, 29 Sup. Ct. 192, 200 (53 L. Ed. 382, 15 Ann. Cas. 1034, 48 L. R. A. [N. S.] 1134).

'The ascertainment of that value is not controlled by artificial rules. It is not a matter of formulas, but there must be a reasonable judgment having its basis in a proper consideration of all relevant facts.' Minnesota Rate Cases (1913) 230 U. S. 352, 434, 33 Sup. Ct. 729, 754 (57 L. Ed. 1511, 48 L. R. A. [N. S.] 1151, Ann. Cas. 1916A, 18).

***691** 'And in order to ascertain that value, the original cost of construction, the amount expended in permanent improvements, the amount and market value of its bonds and stock, the present as compared with the original cost of construction, the probable earning capacity of the property under particular rates prescribed by statute, and the sum required to meet operating expenses, are all matters for consideration, and are to be given such weight as may be just and right in each case. We do not say that there may not be other matters to be regarded in estimating the value of the property.' Smyth v. Ames, 169 U. S., 546, 547, 18 Sup. Ct. 434, 42 L. Ed. 819.

'* * * The making of a just return for the use of the property involves the recognition of its fair value if it be more than its cost. The property is held in private ownership and it is that property, and not the original cost of it, of which the owner may not be deprived without due process of law.'

Minnesota Rate Cases, 230 U. S. 454, 33 Sup. Ct. 762, 57 L. Ed. 1511, 48 L. R. A. (N. S.) 1151, Ann. Cas. 1916A, 18.

In Missouri ex rel. Southwestern Bell Telephone Co., v. Public Service Commission of Missouri, supra, applying the principles of the cases above cited and others, this court said:

'Obviously, the commission undertook to value the property without according any weight to the greatly enhanced costs of material, labor, supplies, etc., over those prevailing in 1913, 1914, and 1916. As matter of common knowledge, these increases were large. Competent witnesses estimated them as 45 to 50 per centum. * * * It is impossible to ascertain what will amount to a fair return upon properties devoted to public service, without giving consideration to the cost of labor, supplies, etc., at the time the investigation is made. An honest and intelligent forecast of probable future values, made upon a view of all the relevant circumstances, is essential. If the highly important element of present costs is wholly disregarded, such a forecast becomes impossible. Estimates for to-morrow cannot ignore prices of to-day.'

[5] ***692** It is clear that the court also failed to give proper consideration to the higher cost of construction in 1920 over that in 1915 and before the war, and failed to give weight to cost of reproduction less depreciation on the basis of 1920 prices, or to the testimony of the company's valuation engineer, based on present and past costs of construction, that the property in his opinion, was worth $900,000. The final figure, $460,000, was arrived ****679** at substantially on the basis of actual cost, less depreciation, plus 10 per cent. for going value and $10,000 for working capital. This resulted in a valuation considerably and materially less than would have been reached by a fair and just consideration of all the facts. The valuation cannot be sustained. Other objections to the valuation need not be considered.

3. Rate of return: The state commission found that the company's net annual income should be approximately $37,000, in order to enable it to earn 8 per cent. for return and depreciation upon the value of its property as fixed by it. Deducting 2 per cent. for depreciation, there remains 6 per cent. on $460,000, amounting to $27,600 for return. This was approved by the state court.

[6] The company contends that the rate of return is too low and confiscatory. What annual rate will constitute just compensation depeds upon many circumstances, and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding, risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in ***693** highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A

rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

In 1909, this court, in Willcox v. Consolidated Gas Co., 212 U. S. 19, 48-50, 29 Sup. Ct. 192, 53 L. Ed. 382, 15 Ann. Cas. 1034, 48 L. R. A. (N. S.) 1134, held that the question whether a rate yields such a return as not to be confiscatory depends upon circumstances, locality and risk, and that no proper rate can be established for all cases; and that, under the circumstances of that case, 6 per cent. was a fair return on the value of the property employed in supplying gas to the city of New York, and that a rate yielding that return was not confiscatory. In that case the investment was held to be safe, returns certain and risk reduced almost to a minimum-as nearly a safe and secure investment as could be imagined in regard to any private manufacturing enterprise.

In 1912, in Cedar Rapids Gas Co. v. Cedar Rapids, 223 U. S. 655, 670, 32 Sup. Ct. 389, 56 L. Ed. 594, this court declined to reverse the state court where the value of the plant considerably exceeded its cost, and the estimated return was over 6 per cent.

In 1915, in Des Moines Gas Co. v. Des Moines, 238 U. S. 153, 172, 35 Sup. Ct. 811, 59 L. Ed. 1244, this court declined to reverse the United States District Court in refusing an injunction upon the conclusion reached that a return of 6 per cent. per annum upon the value would not be confiscatory.

In 1919, this court in Lincoln Gas Co. v. Lincoln, 250 U. S. 256, 268, 39 Sup. Ct. 454, 458 (63 L. Ed. 968), declined on the facts of that case to approve a finding that no rate yielding as much as 6 per cent. ***694** on the invested capital could be regarded as confiscatory. Speaking for the court, Mr. Justice Pitney said:
'It is a matter of common knowledge that, owing principally to the World War, the costs of labor and supplies of every kind have greatly advanced since the ordinance was adopted, and largely since this cause was last heard in the court below. And it is equally well known that annual returns upon capital and enterprise the world over have materially increased, so that what would have been a proper rate of return for capital invested in gas plants and similar public utilities a few years ago furnishes no safe criterion for the present or for the future.'

In 1921, in Brush Electric Co. v. Galveston, the United States District Court held 8 per cent. a fair rate of return. FN4

FN4 This case was affirmed by this court June 4, 1923, 262 U. S. 443, 43 Sup. Ct. 606, 67 L. Ed. 1076.

In January, 1923, in City of Minneapolis v. Rand, the Circuit Court of Appeals of the Eighth Circuit (285 Fed. 818, 830) sustained, as against the attack of the city on the ground that it was excessive, 7 1/2 per cent., found by a special master and approved by the District Court as a fair and reasonable return on the capital investment-the value of the property.

[7] Investors take into account the result of past operations, especially in recent years, when determining the terms upon which they will invest in such an undertaking. Low, uncertain, or irregular income makes for low prices for the securities of the utility and higher rates of interest to be demanded by investors. The fact that the company may not insist as a matter of constitutional right that past losses be made up by rates to be applied in the present and future tends to weaken credit, and the fact that the utility is protected against being compelled to serve for confiscatory rates tends to support it. In ***695** this case the record shows that the rate of return has been low through a long period up to the time of the inquiry by the commission here involved. For example, the average rate of return on the total cost of the property from 1895 to 1915, inclusive, was less than 5 per cent.; from 1911 to 1915, inclusive, about 4.4 per cent., without allowance for depreciation. In 1919 the net operating income was approximately $24,700, leaving $15,500, approximately, or 3.4 per cent. on $460,000 fixed by the commission, after deducting 2 per cent. for depreciation. In 1920, the net operating income was approximately $25,465, leaving $16,265 for return, after allowing for depreciation. Under the facts and circumstances indicated by the record, we think that a rate of return of 6 per cent. upon the value of the property is substantially too low to constitute just compensation for the use of the property employed to render the service.

The judgment of the Supreme Court of Appeals of West Virginia is reversed.

Mr. Justice BRANDEIS concurs in the judgment of reversal, for the reasons stated by him in Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri, supra.
U.S. 1923
Bluefield Waterworks & Imp. Co. v. Public Service Commission of W. Va.
P.U.R. 1923D 11, 262 U.S. 679, 43 S.Ct. 675, 67 L.Ed. 1176

END OF DOCUMENT

NONRECURRING CHARGE COST JUSTIFICATION

Type of Charge:____

1. Field Expense:

A. Materials (Itemize)

______________________________	$__________
______________________________	__________
______________________________	__________

B. Labor (Time and Wage)

______________________________	__________

Total Field Expense **$**__________

2. Clerical and Office Expense

A. Supplies $__________

B. Labor __________

Total Clerical and Office Expense **$**__________

3. Miscellaneous Expense

A. Transportation $__________

B. Other (Itemize)

______________________________	__________
______________________________	__________
______________________________	__________

Total Miscellaneous Expense **$**__________

Total Nonrecurring Charge Expense **$**__________

WATER UTILITY INDUSTRY

INDUSTRY TIMELINESS: 64 (of 93)

The Water Utility Industry consists of six investor-owned companies that provide water services to residential, commercial, and industrial customers. The group is extremely small because most of the water utilities in the United States are run by states and local municipalities. The fundamentals in this Industry do not change quickly. Change comes incrementally here, which can be both good and bad. Almost every water utility in the country is playing catch up. For years, the nation's pipelines and wastewater facilities had been falling into disrepair. Over the past decade,or so, the Industry has been investing heavily to replace these older assets.

All utilities are overseen by some state authority that decides on what rates water users will ultimately pay. Fortunately, the relations between the Industry and regulators has been very constructive in the recent past. These relationships may be tested in the coming years because of inflation.

Earnings in the Water Industry are well defined. The demand for water is mostly inelastic, except for when rates are raised meaningfully during a drought or water emergency to dampen demand. Almost all of these stocks score well for Price Stability, Price Growth Persistence, and Earnings Predictability.

In the past three months, the equities in this group have outperformed the market averages.

Fundamentals

Members of this group are all in the midst of large ongoing construction programs that ought to take decades to complete. For years, insufficient capital was allocated to upgrading and modernizing the country's water infrastructure. Indeed, the average age of many pipelines is now between 60 and 75 years. As a result, in an era in which water has become scarcer, a large volume of it was leaking and being wasted due to a shoddy transmission system. Both the utilities and regulators are to blame for the predicament because neither party wanted to receive backlash from raising customers' bills to make the required improvements. In any case, the industry has taken steps to correct this situation. Instead of one massive spending program, the outlays will be made gradually.

Mediocre Finances

To fund the building projects, most utilities have to depend, in part, on external financing. Over the past 15 years, we have been in a low interest rate environment and debt was the preferred source of financing. With interest rates for long-maturity corporate bonds spiking higher, there is a chance that this could change. Many water utilities have been reluctant to issue equity in the past. Since the industry's stocks are now trading with historically high P/E ratios (more below), we think now would be a good time to sell shares. For example, eleven years ago, *American Water Works* had 175.66 million shares outstanding. When 2022 ended, we estimated the figure rose to just 182 million, a meager annual growth rate of 0.3%. (The company hasn't had any kind of stock repurchase program.) Over that same time, *American Water's* long-term debt-to total capital ratio has increased. While this is not a weak balance sheet, it can't be classified as strong either. This also applies to most water utilities.

Scarcity Of Stocks

The total market capitalization of the Water Utility Industry is about $51 billion, or slightly below that of Dominion Energy, the nation's fourth largest electric utility. Moreover *American Water Works* accounts for over 54% of the total. Thus, in the group there are only two large cap stocks. (The other *Essential Utilities*.) That leaves 4 companies that have market caps ranging from $2.5 billion to $3.4 billion. The demand to own shares by the large institutional investors clearly outstrips the supply. This is one of the prime reasons for these stocks trading at such seemingly inflated P/E ratios. Of the six water stocks covered by *Value Line*, the P/E's range from a low of 24.8, to a high of 38.8, with the average being 32.4. *Essential Utilities* is the only equity with a P/E below 30, mostly because of its gas utility operations.

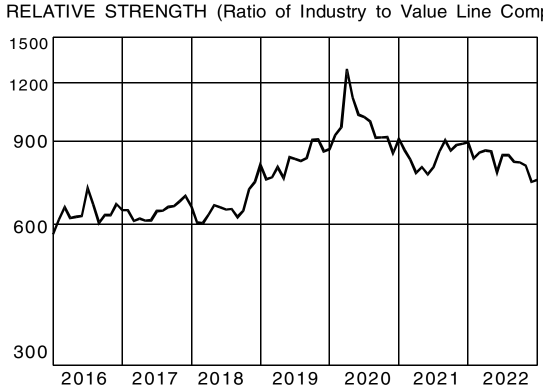
Conclusion

Should investors want to become involved in this sector, they must be willing to pay a huge premium. While this sector has several positive attributes, it also has a severe limitations. For one, the returns on equity are determined by an outside entity. Thus, there is a ceiling to each company's profit potential. Furthermore, regulators can be fickle. The water industry has enjoyed positive relations with regulators over the past decade or so, but that was during a time of very low inflation. Passing along the rate hikes needed to finance the replacement of old pipes will likely remain above the level of inflation, which is currently over 6%. State regulatory commissions are under political pressure to keep ratepayers' bills low. So, even though a utility may have spent funds prudently, that does not necessary mean that regulators will allow a fair return to be made on the investment. In the electric utility sector this has happened frequently, mainly due to a backlash from the public. Regulators are appointed by politicians. Elected officials do not gain popular support (i.e. votes) by raising utility bills. In our opinion, Wall Street has not taken this into account, as it certainly is not reflected in the price of the stocks. As always, we urge investors to read each individual report before investing.

James A. Flood

Water Utility

RELATIVE STRENGTH (Ratio of Industry to Value Line Comp.)



Index: June, 1967 = 100

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF BLUEGRASS WATER UTILITY OPERATING COMPANY, LLC FOR AN ADJUSTMENT OF RATES AND APPROVAL OF CONSTRUCTION	)))))	CASE NO. 2020-00290

O R D E R

This matter arises from an application for a rate increase and approval of construction filed by Bluegrass Water Utility Operating Company, LLC (Bluegrass Water) pursuant to KRS 278.020(1), KRS 278.180, and KRS 278.190. The Kentucky Attorney General, through the Office of Rate Intervention (Attorney General) and a number of groups representing Bluegrass Water's customers (collectively, Joint Intervenors)[1] were permitted to intervene in this matter. Bluegrass Water responded to requests for information from the Attorney General, Joint Intervenors, and Commission Staff, and a hearing was conducted in this matter on May 18, 2021, through May 20, 2021. Bluegrass Water responded to post-hearing request for information and Joint Intervenors and the Attorney General filed post-hearing briefs, and Bluegrass Water filed a brief in response to intervenors' post-hearing briefs. This matter is now before the Commission for a decision on the merits.

[1] The groups representing Bluegrass Water's customers are Homestead Home Owners Association, Inc.; The Deer Run Estates Homeowners Association, Inc.; Longview Homeowners Association, Inc.; Arcadia Pines Sewer Association, Inc., Carriage Park Neighborhood Association, Inc., Marshall Ridge Sewer Association, Inc. and Randview Septic Corporation. They are all represented by the same counsel and have therefore acted collectively in the proceedings before the Commission. Thus, the Commission refers to them collectively as Joint Intervenors.

BACKGROUND

Bluegrass Water is a limited liability company organized under the laws of Kentucky on March 21, 2019. Beginning in April 2019, Bluegrass Water began filing applications pursuant to KRS Chapter 278 to purchase water and wastewater systems in Kentucky. On August 14, 2019, Bluegrass Water was approved to purchase the Airview Utilities, LLC (Airview), Brocklyn Utilities, LLC (Brocklyn), Fox Run Utilities, LLC (Fox Run), Marshall County Environmental Services, LLC (Great Oaks and Golden Acres), Kingswood Development, Inc. (Kingswood), Lake Columbia Utilities, Inc. (Lake Columbia), LH Treatment Company, LLC (Longview/Homestead), and P.R Wastewater Management, Inc (Persimmon Ridge) wastewater systems in Hardin, Madison, Franklin McCracken, Marshall, Bullitt, Scott, and Shelby counties.[2] On February 17, 2020, Bluegrass Water was approved to purchase the River Bluffs, Inc. (River Bluffs) and Joann Estates Utilities, Inc. (Timberland) wastewater systems in Oldham and McCracken counties and the Center Ridge Water District, Inc. (Center Ridge) water systems in Calloway County.[3] On June 19, 2020, Bluegrass Water was approved to purchase the Arcadia Pines Sewer Association, Inc. (Arcadia Pines), Carriage Park Neighborhood Association Inc. (Carriage Park), Marshall Ridge Sewer Association Inc. (Marshall Ridge), and Randview Septic Corporation (Randview) wastewater systems in McCracken and

[2] Case No. 2019-00104, *Electronic Proposed Acquisition by Bluegrass Water Utility Operating Company, LLC and the Transfer of Ownership and Control of Assets by P.R. Wastewater Management, Inc., Marshall County Environmental Services, LLC, LH Treatment Company, LLC, Kingswood Development, Inc., Airview Utilities, LLC, Brocklyn Utilities, LLC, Fox Run Utilities, LLC, and Lake Columbia Utilities, Inc.* (Ky. PSC Feb. 25, 2021).

[3] Case No. 2019-00360, *Electronic Proposed Acquisition by Bluegrass Water Utility Operating Company, LLC and the Transfer of Ownership and Control of Assets by Center Ridge Water District, Inc., Joann Estates Utilities, Inc., and River Bluffs, Inc.* (Ky. PSC Feb. 17, 2020).

Graves counties.[4] On January 14, 2021, Bluegrass Water was approved to purchase the Delaplain Disposal Company (Delaplain), Herrington Haven Wastewater Company Inc. (Herrington Haven), Springcrest Sewer Company, Inc. (Springcrest), and Woodland Acres Utilities, LLC (Woodland Acres) wastewater systems in Scott, Garrard, Jessamine, and Bullitt counties. Bluegrass Water is categorized as a class B sewer utility and a class C water utility.

Bluegrass Water tendered its application in this matter on October 1, 2020.[5] However, on October 30, 2020, Bluegrass Water was sent a deficiency letter that identified information required by 807 KAR 5:001, Section 16 that was not provided with the application. On the same day, the Commission issued an Order noting the same deficiencies issued in the letter and stating that Bluegrass Water must cure those deficiencies as directed in the deficiency letter before the application may be accepted for filing. In the October 30, 2020 Order, the Commission also noted that Bluegrass Water had not closed on the Arcadia Pines, Carriage Park, Marshall Ridge, and Randview wastewater systems when it tendered the application and explicitly stated that Bluegrass Water must close on those systems before it cures the deficiencies identified in the letter and the application is accepted for filing if it wanted the application to be considered a request for a rate adjustment for those systems. On November 19, 2020, Bluegrass Water closed on the Arcadia Pines, Carriage Park, Marshall Ridge, and Randview

[4] Case No. 2020-00028, *Electronic Proposed Acquisition by Bluegrass Water Utility Operating Company, LLC of Wastewater System Facilities and Subsequent Tariffed Service to Users Presently Served by those Facilities* (Ky. PSC Jun. 19, 2020).

[5] Note that Bluegrass Water tendered some of the attachments to the application on September 30, 2020 and tendered the application itself on September 30, 2020 in Case No. 2020-00297. Bluegrass Water corrected that issue and tendered the application in this matter on October 1, 2020.

wastewater systems and cured the filing deficiencies identified in the October 30, 2020 letter. Bluegrass Water's application was deemed to have been filed on November 19, 2020.

However, as of November 19, 2020, Bluegrass Water had not been approved to purchase and did not own the systems for which it sought approval to purchase in Case No. 2020-00297; the Delaplain, Herrington Haven, Springcrest, and Woodland Acres sewer systems (the 00297 systems). The Commission denied Bluegrass Water's request for a deviation from 807 KAR 5:011, Section 11, and determined that, pursuant to 807 KAR 5:011, Section 11, and KRS Chapter 278, Bluegrass Water could not file a tariff proposing to increase the rates of the 00297 systems until it completed the purchase of those systems and adopted the existing tariffs of those systems. Thus, the Commission held that Bluegrass Water's application in this matter, which was filed before Bluegrass Water was even approved to purchase those systems, would not be considered as a request to increase the rates of the 00297 systems pursuant to KRS Chapter 278.

Bluegrass Water's application proposes a rate increase based on a forecasted test period ending April 30, 2022, and requests rates based on a total revenue requirement for water and sewer customers of $3,758,757. Bluegrass Water indicated that revenue requirement represents an increase of $2,513,799 over projected revenues derived from current rates for the systems Bluegrass Water owns and operates and the systems it was seeking to operate when it tendered its application. The total proposed revenue requirement consists of a revenue requirement for sewer of $3,332,039.61, including the costs associated with the 00297 systems, and a revenue requirement for water of $426,747. If Bluegrass Water collected its total proposed revenue requirement of

$3,758,757, the rates of its systems would need to be increased by about approximately 200 percent.

Bluegrass Water filed tariff sheets with its application that included a proposed flat, unified rate for residential sewage customers of $96.14 per month and a proposed flat unified rate for residential water customers of $105.84 per month. Bluegrass Water's customers are currently served under separate distinct rates based on the systems that provide them service, which are based on the filed rates or the amounts charged by the previous owners of the systems. Bluegrass Water indicated that residential customers of the sewer systems at issue currently pay flat rates ranging from $15.00 to $55.85 per month such that the proposed rate of $96.14 per month will represent a 72.1 percent to a 540.9 percent increase in residential rates. Bluegrass Water indicated that residential customers of water systems at issue currently pay a flat rate of $22.79 per month such that the proposed rate of $105.84 per month will represent a 364.4 percent increase in those residential rates.

Bluegrass Water, in support of its application, presented schedules and written testimony from Josiah Cox, Todd Thomas, Jacob Freeman, Brent Thies, Dylan D'Ascendis, and Jennifer Nelson. Among other things, Bluegrass Water indicated that the proposed rates are necessary in large part due to the significant capital investment Bluegrass Water has or will make through the forecasted test period. Bluegrass Water asserted that it has made or that it will be necessary to make about $4.39 million in capital investments in the sewage systems at issue, about $1.16 million in capital investments in the water systems at issue, and about $2.01 million in capital investments in the 00297 systems.[6] In its application, Bluegrass Water contended that a Certificate of Public Convenience and Necessity (CPCN) was not required for the projects but alternatively requested a CPCN for any project for a CPCN would be required.

On June 30, 2021, Bluegrass Water filed a notice of intent to implement its proposed rates, which were suspended in a previous Commission Order, on August 1, 2021, pending the final Order and subject to refund as required by KRS 278.190. However, although Bluegrass Water indicated it maintained its objections, it indicated it would not implement any new rate, subject to refund, for the 00297 systems, which it did not own at the time this application was filed.

MISCELLANEOUS ISSUES

Rates of Systems at Issue in Case No. 2020-00028

Joint Intervenors argue that the Commission should reject Bluegrass Water's request for a rate increase with respect to the four systems Bluegrass Water was approved to purchase in Case No. 2020-00028, which are Arcadia Pines, Carriage Park, Marshall Ridge, and Randview (collectively, the 00028 systems). Joint Intervenors note that Bluegrass Water closed on those systems the same day its application was accepted for filing in this matter. Joint Intervenors argue that Bluegrass Water could not file a rate application based on a forecasted test period for those customers, because KRS 278.192 requires six months of actual historical data to support a rate case based on a forecasted test period. Joint Intervenors also argue that Bluegrass Water, in its application in Case No. 2020-00028, committed to waiting to file for a rate increase for those systems until

[6] *See generally* Application, Exhibit 8, Direct Testimony of Jacob Freeman (Freeman Testimony).

Bluegrass Water had one year of historical data from owning and operating those systems.[7]

Bluegrass Water disputes Joint Intervenors' interpretation of KRS 278.192. It notes that it had more than six months of historical data from operations when it filed its application in this matter. Bluegrass Water argues that information is sufficient to comply with KRS 278.192, even though it did not have six months of historical data for the 00028 systems. Bluegrass Water also disputes that it committed not to increase the rates of the 00028 systems for a year in its application in Case No. 2020-00028. Bluegrass Water argues that the issue in Case No. 2020-00028 was that the systems were not being operated as rate-regulated utilities by the former owners such that there was no tariff on file for Bluegrass Water to adopt pursuant to 807 KAR 5:011 and insufficient information to establish rates pursuant to 807 KAR 5:076.[8] Bluegrass Water stated that it proposed initial rates for the 00028 systems based on the amounts charged by the current owners and that it then "committed" to apply for a rate adjustment for those systems "no later than 15 months after their acquisition."[9] Bluegrass Water also notes that it indicated it would file such an application "by mid-2021." Bluegrass Water argues that intervenors are incorrect in stating that "Bluegrass 'originally indicated' (AG Brief. p.7) or made an 'express commitment' or 'regulatory commitment' (Jt. Int. Brief pp. 5-6) to wait until mid-

[7] Joint Intervenors' Post-Hearing Brief (Joint Intervenors' Brief) (filed June 3, 2021) at 5-7.

[8] Bluegrass Water's Post-Hearing Response Brief (Bluegrass Water Response Brief)(filed June 9, 2021) at 3.

[9] *Id.* at 4.

2021 to file for an adjustment of rates for the 00028 systems or state-wide."[10] Bluegrass Water also argues that the Commission's final Order in Case No. 2020-00028 did not explicitly condition approval of the transfers on Bluegrass Water agreeing to wait until mid-2021 to apply for a rate increase.[11]

If the Commission accepted Joint Intervenors' argument with respect to the interpretation of KRS 278.192, it would essentially be holding that KRS 278.192 prevents a utility from including the customers of a system it purchased within six months in an application for a rate increase based on a forecasted test period. The Commission does not believe that such an interpretation is supported by the plain reading of the statute. Further, there was no explicit commitment or condition in Case No. 2020-00028 requiring Bluegrass Water to wait to file for a rate increase for the 00028 systems. Thus, the Commission finds no reason that Joint Intervenors' request that the Commission reject the proposed rate increase as it pertains to the 00028 systems should be granted.

However, the Commission notes that when a utility files an application for a rate increase that "the burden of proof to show that the increased rate or charge is just and reasonable shall be upon the utility."[12] If a utility includes a new system without accurate historical data, then it may be unable to meet its burden, and the Commission may reject or reduce the proposed rate as appropriate.

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[10] *Id.*

[11] *Id.*

[12] KRS 278.190.

Rates of Systems at Issue in Case No. 2019-00104

Joint Intervenors argue that Bluegrass Water broke an additional commitment to the Commission by filing a rate case using a forecasted test year for the systems acquired in Case No. 2019-00104 (the 00104 systems), because Josiah Cox, President of Bluegrass Water, had testified at a hearing in Case No. 2019-00104 that its first rate filing would be based upon the company's "current expenses." Joint Intervenors argue that Bluegrass Water seeks to inject millions of dollars of additional rate base and operation and maintenance expense into its revenue requirement. Joint Intervenors argue that Bluegrass Water should not be able to use a forecasted test year based on its commitment to use "current expenses."

Bluegrass Water responded that Mr. Cox, after explaining that "historical information is not necessarily informative," answered a question regarding a timeline for seeking a unified rate by stating: "[W]e would run the systems for some period of time before we would come back and apply for a unified rate based on what our current costs are."[13] Bluegrass Water argued that in context the statement is to distinguish such a rate filing from one based on the past owners historical expenses. Further, Bluegrass Water claims that this current rate case is based on its current expenses, due to the inclusion of 2020 base year actuals.[14] Bluegrass Water argues that there is no justification for prohibiting a rate adjustment through use of a forecasted test year from including the 00104 systems.

[13] Bluegrass Water's Response Brief at 4, footnote 4.

[14] *Id.*

The Commission agrees with Bluegrass Water that the statement made by Mr. Cox at the hearing in Case No. 2019-00104 would not prohibit Bluegrass Water from filing a rate adjustment based on a forecasted test year that included the 00104 systems. Given the context of the statement, it was not an explicit commitment to file a rate case based on a historical test year. Further, KRS 278.192 allows Bluegrass Water to apply for a rate increase based on a forecasted test year for the systems at issue in Case No. 2019-00104, and Joint Intervenors have not provided any basis for finding that the statute would not apply under the circumstances. Thus, the Commission finds that the Joint Intervenors' request that the proposed rate increase be dismissed for the 00104 systems or that rates be limited to purely historical information for those systems should not be granted.[15]

Exclusion of Systems at Issue in Case No. 2020-00297

Joint Intervenors argue that the Commission correctly found, in a February 12, 2021 Order, that Bluegrass Water had not adopted the tariffs of the 00297 systems when it filed the application in this matter and, therefore, that Bluegrass Water could not apply for a rate increase for the customers of those systems as part of this application. Joint Intervenors further argue that all proposed capital investments for the systems acquired in Case No. 2020-00297 be removed for ratemaking purposes in this proceeding.[16] Joint Intervenors point out that the systems in question were not owned by Bluegrass Water at the time the application for the current proceeding was tendered and state that there is

[15] The Commission also notes that even if it limited the 00104 systems to a historical test period that Bluegrass Water would be able to project known and measurable changes.

[16] Joint Intervenors' Brief at 4.

no precedent for a Kentucky utility utilizing a forecast test year to raise rates on customers of a system that it does not yet own.[17]

Joint Intervenors also argue that exclusion of the plant for the 00297 systems is justified by the "used and useful" doctrine. Specifically, Joint Intervenors assert that the systems owned by Bluegrass Water do not draw service from a centralized source and operate independently of one another such that capital expenditures made to rehabilitate one system will never benefit the customers of another system. Thus, Joint Intervenors argue that the sharing of these costs across systems is unjust.[18]

Bluegrass Water states that it based its application for an adjustment of rates on a fully forecasted test year ending April 30, 2022. Bluegrass Water indicated that it proposed a unified rate for all systems forecast to be owned and operated by Bluegrass Water during the forecasted test period. Bluegrass Water asserts that it in fact does now own the 00297 systems as forecasted. Bluegrass Water noted that it disputes the Commission's order to exclude the 00297 systems from the rate adjustment, "but here neither waives nor repeats arguments against exclusion."[19]

Bluegrass Water contends that Joint Intervenors' attempt to revisit the decision to exclude the 00297 systems advances "tendentious arguments purportedly in support of the Commission's decision, most notably a radical position that costs for necessary investment in treatment or collection/distribution infrastructure cannot be recovered from

[17] *Id.*

[18] *Id.*

[19] Bluegrass Water's Response Brief at 2–3.

'consumers who will never benefit from them.'"[20] Bluegrass Water asserts that the rule proposed by Joint Intervenors would require individualized rates for each service location. Bluegrass Water notes that such a rule is violated each time rates are set and gave the example of a rate for a long established electric customer that includes the cost to construct new transmission and distribution lines to extend the service area or a reach new residential, commercial, or industrial development. Bluegrass Water argues that "[n]either law nor policy supports atomizing rates or de-averaging based on the nearest facilities and how close the customer is to them."[21]

As an initial matter, for the reasons expressed in previous orders, the Commission sees no reason to reconsider its previous decisions in the February 12, 2021 Order and the March 24, 2021 Order on reconsideration denying Bluegrass Water's request for a deviation and finding that Bluegrass Water must first adopt the existing tariffs of the utilities at issue in Case No. 2020-00297, pursuant to 807 KAR 5:011, Section 11, before filing a tariff proposing to increase rates for those systems, pursuant the 807 KAR Chapter 5 and KRS Chapter 278, with 30 days' notice to the Commission.[22] Further, as the Commission noted in the orders addressing that issue, Bluegrass Water is proposing to combine the separate rates of multiple systems into a single rate in this matter and,

[20] *Id.* at 2.

[21] *Id.*

[22] The Commission observes that Bluegrass Water adopted the tariffs of the previous utilities at the end of March 2021 and that in April 2021 Bluegrass Water filed tariffs bringing those systems within its tariff, which included separate rate sheets for each of those systems, consistent with the rate sheets it attached as an exhibit in Case No. 2020-00297 and indicated it would file, setting rates for those systems at the same level as the previous owner. Bluegrass Water has filed no new tariff sheets proposing to increase the rates of those or any other systems since those tariffs were filed.

therefore, the Commission would be looking at the costs attributable to each system separately, even if the Commission ultimately adopted a unified rate for the systems at issue in this case, when reviewing whether the proposed rates were reasonable.[23] The issue raised by Joint Intervenors is, in part, whether it is reasonable to include costs attributable to separate systems that are not included in a unified rate.

While the Commission, as discussed herein, is approving a unified rate for the systems at issue in this case, the Commission finds that it is not reasonable to include the costs of systems not included here among the costs that would be recovered from other customers. As discussed in more detail below, there are reasons for approving a unified rate as opposed to a single rate for each system, including that a unified rate is likely to promote regionalization, which should drive down costs in the long term by allowing utilities to take advantage of economies of scale, and that a unified rate will serve to levelize rates in the long term so that each system will not experience a significant rate shock every time it requires significant investment or some unexpected cost, which all systems will experience at some point. However, such cost sharing is not reasonable where the customers of a distinct system with wholly separate rates is not included in the unified rate. Thus, the Commission finds that the costs associated with the 00297 systems should not be included in establishing the revenue requirement for a unified rate in this matter and that they should be treated as distinct systems, whose rates are not at issue, for the purpose of setting rates for systems at issue in this matter.[24]

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[23] *See* Order (Ky. PSC Mar. 24, 2021) at 8–9.

[24] As Bluegrass Water noted, the inclusion of the 00297 systems in the unified rate would have actually lowered the overall rate.

As discussed in more detail below, the Commission will remove all capital costs associated with the 00297 systems when determining the revenue requirement for the systems at issue in this matter. Similarly, the Commission finds that operating revenues and expenses associated with the 00297 systems should be removed.

Governance and Accountability

Joint Intervenors assert that Bluegrass Water's Operating Agreement allows its sole member, CSWR, LLC (CSWR), to reorder the priority of making both regular and capital distributions and distributions upon the dissolution of the company. Joint Intervenors argue that "the governing documents expressly permit CSWR to take advantage of Bluegrass Water and, by extension, their customers," though Joint Intervenors acknowledge that it is probably unlikely to happen.[25]

While Joint Intervenors are not specific, they appear to be concerned that Bluegrass Water would make payments to CSWR before making payments to creditors or contractors. The Commission notes that Bluegrass Water already has a statutory obligation to provide adequate service to customers and that Bluegrass Water is prohibited from transferring utility assets without prior Commission approval. The Commission does not believe that additional conditions are appropriate at this time, though it may revisit imposing conditions, pursuant to KRS 278.300, on the order of payment when Bluegrass Water applies for financing approval.

Procedural Issues

Bluegrass Water tendered a document titled "Statement of Non Existence/ Inapplicability of Certain Rate-Application Requirements or, in the alternative, Request

[25] Joint Intervenors' Brief at 25.

for Waiver of Requirement(s)" with its application in this matter. At the hearing in this matter, Bluegrass Water identified this document as a motion on which the Commission had not yet ruled. However, the requirements either were satisfied by the information or explanation provided or were not applicable to this case.[26] Further, the document was not clear that it was intended to be a motion filed pursuant to 807 KAR 5:001 in the event the Commission found that no waiver from the filing requirements was necessary, and no deficiency relevant to filing requirements mentioned was identified. Thus, the Commission finds that there is no need to take any action on this document.

Bluegrass Water also filed a motion for an enlargement of time to respond to Commission Staff's Third Request for Information. Specifically, responses to the requests were due on March 22, 2021, and Bluegrass Water partially responded on that date, but noted that it was still compiling information to respond to additional requests for information and requested until March 26, 2021, to provide that information. Having reviewed that motion and being otherwise sufficiently advised, the Commission will grant that motion as it indicated it would at the hearing in this matter.

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

Bluegrass Water and Intervenors' Positions

Bluegrass Water indicated in its application that it planned projects, itemized in the testimony of Jacob Freeman, to repair, replace, and improve the sewer and water facilities

[26] *See* 807 KAR 5:001, Section 16(7) (indicating that a utility should provide the explanation "or a statement explaining why the required information does not exist and is not applicable to the utility's application").

it owns and operates or was approved or requested approval to own and operate.[27] Bluegrass Water acknowledged in testimony and other filings made with its application that it had started some of the projects when it filed its application.[28] Bluegrass Water argued that most of its projects are needed to maintain capacity and basic functionality of the systems or to achieve compliance with environmental regulations, and that other projects will achieve operational efficiencies as well as enhance the present quality of service for Bluegrass Water's customers.[29]

Bluegrass Water asserted in its application that "[a]ll or most of the individual projects would not be categorized as new construction or extensions for which a [CPCN] is needed."[30] Bluegrass Water argued that the projects do not extend the Bluegrass Water service area, do not create a wasteful duplication, or conflict with the service offered by other utilities.[31] Bluegrass Water requested a finding that a CPCN is not needed for any one of the projects or, in the alternative, Bluegrass Water requests a CPCN for any projects that are found to be subject to the requirement that a CPCN be obtained.[32]

At the hearing, Josiah Cox, Bluegrass Water's President, testified that he felt a CPCN would be necessary if the project involved the construction of a new tank or

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[27] Application at 11.

[28] Response to Attorney General's Post-Hearing Requests, Item 1, AG_post-hearing_DR01.xlsx (indicating the amounts spent on each of the projects identified in Mr. Freeman's testimony to date).

[29] Application at 14.

[30] Application at 11–12.

[31] Application at 12.

[32] Application at 12.

process.[33] He said that he identified a number of projects that had not been completed that he felt met that criteria and, therefore, would require a CPCN. Specifically, he indicated that he believed the following projects would require a CPCN:

1. The addition of a flow equalization tank at Airview;
2. The construction of a new plant at Brocklyn;
3. The addition of flow equalization and a sludge digester at Fox Run;
4. The addition of a sludge digester at Lake Columbia;
5. The addition of a moving bed bioreactor at Permission Ridge;
6. The conversion of the plant at Delaplain to a moving bed bioreactor to increase the capacity of the plant and the addition of a strainer;
7. The addition of a moving bed bioreactor at Herrington Haven; and
8. The conversion of the Woodland Acres systems to a moving bed bioreactor.[34]

Joint Intervenors argue that Bluegrass Water overlooked the requirement that a project must "not involve sufficient capital outlay to materially affect the existing financial condition of the utility involved" or "result in increased charges to its customers" when arguing that a CPCN is not necessary.[35] Joint Intervenors, referring to Mr. Cox's testimony, contend that Bluegrass Water acknowledged that the capital projects are material to its financial condition and will result in a rate increase.[36] They also assert that

[33] May 19, 2021 Hearing Video Transcript (H.V.T.) at 09:41:40.

[34] May 19, 2021 H.V.T. at 09:39:51-09:41:40.

[35] Joint Intervenors' Brief at 20.
[36] Joint Intervenors' Brief at 21.

it is not credible for Bluegrass Water to argue that its actual construction projects to date did not require a CPCN given the level of spending Bluegrass Water proposed and has completed.[37] Joint Intervenors further argue that Bluegrass Water made structural improvements and replaced major components of its newly acquired systems.[38] Thus, Joint Intervenors argue Bluegrass Water's projects do not qualify as extensions of existing systems in the usual course of business and, therefore, that a CPCN is required for all of the projects proposed by Bluegrass Water.[39]

Joint Intervenors next argue that no CPCN should be awarded for additional capital investment until Bluegrass Water certifies the actions it has taken to explore reasonable alternatives. Joint Intervenors assert that when pressed about reasonable alternatives to proposed projects that Bluegrass Water could not provide details on what connections to other systems might be available or when discussions regarding additional available connections might take place. Joint Intervenors state, referring to Bluegrass Water's response to post-hearing data requests, that the projects for which Bluegrass Water requests a CPCN are all systems within one mile of other systems. Joint Intervenors contend that Bluegrass Water has not established that its projects are the reasonable, least cost alternatives. Joint Intervenors argue that the Commission should either (1) deny the request for CPCNs or further capital investment for these systems without

[37] Joint Intervenors' Brief at 21–23.

[38] Joint Intervenors' Brief at 23 (citing May 18, 2021 H.V.T. 14:04:30–14:40:30).

[39] Joint Intervenors' Brief at 23.

prejudice; or (2) keep this portion of Bluegrass's case open and pending for further action following the entry of a rate order within the suspension period.[40]

The Attorney General argues that the Commission should scrutinize each of Bluegrass Water's capital projects to ensure that all construction projects undertaken by Bluegrass Water are in furtherance of maintaining only basic functionality of each system and ensure that wasteful gold plating of the systems does not occur. The Attorney General specifically questions the Mission alarm installation and remote monitoring proposed in the application. The Attorney General notes that to comply 807 KAR 5:071(7)(4), Bluegrass Water's contractors will need to visit the systems daily to inspect all mechanical equipment. The Attorney General argues that remote monitoring may constitute unnecessary duplication of service if contractors will be physically present at each system daily and that such wasteful duplication should be denied.[41]

Discussion of When a CPCN is Required

KRS 278.020(1)(a) generally requires a utility to obtain a CPCN before beginning the construction of any plant, equipment, property, or facility for furnishing to the public any utility, including water and sewer service. However, a CPCN is not required for "ordinary extensions of existing systems in the usual course of business."[42] An "ordinary extension . . . in the usual course of business" is not defined in KRS 278.020 or elsewhere

[40] Joint Intervenors' Brief at 23–24.

[41] Attorney General's Post-Hearing Brief (AG's Brief)(filed June 3, 2021) at 3–4.

[42] KRS 278.020(1)(a)1.

in KRS Chapter 278. For that reason, the Commission promulgated 807 KAR 5:001, Section 15(3),[43] which states:

> Extensions in the ordinary course of business. A certificate of public convenience and necessity shall not be required for extensions that do not create wasteful duplication of plant, equipment, property, or facilities, or conflict with the existing certificates or service of other utilities operating in the same area . . . . , *and* that do not involve sufficient capital outlay to materially affect the existing financial condition of the utility involved, or will not result in increased charges to its customers.[44]

The Commission has interpreted 807 KAR 5:001, Section 15(3) as stating that no CPCN is required for extensions "that do not result in the wasteful duplication of utility plant, do not compete with the facilities of existing public utilities, and do not involve a sufficient capital outlay to materially affect the existing financial condition of the utility involved or to require an increase in utility rates."[45] The Commission has almost always indicated that proposed construction that exceeds 10 percent or more of a utilities net plant in service is material and, therefore, requires a CPCN,[46] but has also found that smaller capital investments require a CPCN.[47]

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[43] Case No. 2000-00481, *Application of Northern Kentucky Water District (A) for Authority to Issue Parity Revenue Bonds in the Approximate Amount of $16,545,000; and (B) A Certificate of Convenience and Necessity for the Construction of Water Main Facilities* (Ky. PSC Aug. 30, 2001), Order at 4.

[44] 807 KAR 5:001, Section 15(3) (emphasis added).

[45] Case No. 2000-00481, *Northern Kentucky Water District* (Ky. PSC Aug. 30, 2001), Order at 4.

[46] *See, e.g.,* Case No. 2014-00277, *In the Matter of: Springcrest Sewer Co., Inc. Request for Deviation from 807 KAR 5:071, Section 7(4)*, (Ky. PSC Dec. 16, 2014) Order (finding that a remote monitoring system that exceeded 10% of a utilities net plant in service was material and, therefore, required a CPCN).

[47] *See, e.g.,* Case No. 2018-00281, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates*, (Ky. PSC May 7, 2019) Order (discussing a 2% materiality threshold).

There is really no question, based on the records presented in the current matter, that Bluegrass Water's capital projects collectively are material to Bluegrass Water's existing financial condition and will result in increased charges to Bluegrass Water's customers, either now or in the future. Conversely, some individual "construction items" identified for specific systems likely would not materially affect Bluegrass Water's financial condition. Thus, the question regarding the application of the ordinary course of business exception is whether Bluegrass Water's proposed repairs, replacements, and improvements should be reviewed for materiality separately, collectively, or in some other combination.

Neither the statute nor the regulation explicitly state when various projects and subprojects should be considered a single extension for the purpose of determining whether construction falls into the stated exception. However, the Court in *Kentucky Utilities Co. v. Pub. Serv. Comm'n.*, 252 S.W.2d 885 (Ky. 1952) noted the absence of wasteful duplication is an element for determining whether to grant a CPCN and then defined wasteful duplication as "an excess of capacity over need" and "an excessive investment in relation to productivity or efficiency, and an unnecessary multiplicity of physical properties." The Court further noted that:

> An inadequacy of service might be such as to require construction of an additional service facility to supplement an inadequate existing facility, yet the public interest would be better served by substituting one large facility, adequate to serve all the consumers, in place of the inadequate existing facility, rather than constructing a new small facility to supplement the existing small facility. A supplementary small facility might be constructed that would not create duplication from the standpoint of an excess of capacity, but would result in duplication from the standpoint of an excessive investment in relation to efficiency and a multiplicity of physical properties.

If KRS 278.020(1) were interpreted in a manner that allowed a utility to avoid the CPCN requirements by breaking out each discrete construction item or subproject as a separate extension, then the utility could, in part, avoid the analysis anticipated by the Court in *Kentucky Utilities Co*. and the legislature by measuring a single item necessary to repair, replace, or improve existing plant against the alternative instead of measuring all necessary construction on that plant against the alternative. Further, while significant overall capital investment in a short period may raise questions regarding whether a CPCN is necessary for certain projects, it would similarly be inconsistent with the statute and the Commission's past practice to review all of a utility's capital projects in a given period when determining whether the ordinary course of business exception applies.

Here, the Commission finds that all of the repairs and updates proposed to each sewage treatment facility should be reviewed collectively to determine the applicability of the ordinary course of business exception. Bluegrass Water is proposing significant construction on many of its treatment facilities nearly simultaneously such that the wasteful duplication analysis will require a collective review of the projects to determine whether they will result in wasteful duplication. Further, while Bluegrass Water made some updates to construction proposed for some systems, the construction items Bluegrass Water is proposing for each system were generally developed as part of a single plan for each system.[48] Similarly, when asked about the projects that support the additions in the base period and the forecasted period, Bluegrass Water identified all

[48] *See* Response to Staff's Second Request, Item 27, 2 PSC 27 Engineering Memos Unredacted.pdf.

construction on each system as a single project.[49] Thus, at a minimum, the Commission finds that the proposed construction for each system should be analyzed collectively to determine whether a CPCN is required and, if so, whether it should be granted.

In reviewing Bluegrass Water's proposed construction, the Commission finds that a CPCN is necessary or should have been obtained for the construction, which includes repairs and upgrades, to the wastewater treatment facilities at Airview, Brocklyn, and Delaplain, as proposed in Mr. Freeman's testimony. Among other things, Bluegrass Water's estimated cost for the proposed upgrades to the treatment facilities at each of those systems, not including the engineering costs, exceeded the value of Bluegrass Water's net plant in service at the beginning of the base period, based on the schedules Bluegrass Water filed with its application, before Bluegrass Water began significant work on any of the projects. The estimated costs of the proposed repairs and upgrades at those systems similarly made up a significant portion of Bluegrass Water's projected net sewer plant in service at the end of the base period, which includes some of the same work at issue. The cost of those facilities also would represent a significant portion of Bluegrass Water's revenue in both the base and the forecasted periods. Thus, the Commission finds that the proposed construction at those wastewater treatment plants are not extensions in the ordinary course of business and, therefore, that a CPCN must or should have been obtained pursuant to KRS 278.020(1).

The Commission also finds that a CPCN should have been obtained for the construction, including repairs and upgrades, to the wastewater treatment facilities at

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[49] *See* Response to Staff's Second Request, Item 6, 2-PSC-06_(sewer).xlsx (in which Bluegrass Water was asked about all projects included as CWIP or plant in service and it identified all work on each system collectively as a single project).

River Bluffs, which Bluegrass Water reported cost about $439,705 to date, not including remote monitoring equipment, despite an initial estimate of about $120,000. As with the repairs and upgrades proposed at the treatment facilities mentioned above, that capital expenditure is significant in relation to Bluegrass Water's plant in service and its revenue. Thus, the Commission finds that the proposed construction at that wastewater treatment plant is not an extension in the ordinary course of business and, therefore, that a CPCN should have been obtained pursuant to KRS 278.020(1).

Lastly, the Commission finds that a CPCN should have been obtained before Bluegrass Water implemented and began construction of electronic monitoring with its Mission monitoring facilities. The Commission observes that Bluegrass Water's decision to implement electronic monitoring of all of its facilities in Kentucky is akin to other utilities seeking to implement Advanced Metering Infrastructure or related smart grid technology system wide where none previously existed. The Commission has often found that such plans are not extensions in the ordinary course of business and, therefore, that a CPCN is required for the initial implementation.[50] Additionally, here, based Mr. Freeman's testimony, the total capital costs of the proposed Mission monitoring equipment was approximately $298,000 and the systems require the payment of monthly operating

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[50] Case No. 2021-00428, *Consideration of the Implementation of Smart Grid and Smart Meter Technologies*, (Ky. PSC Apr. 13, 2016) Order ("the Commission finds it appropriate for jurisdictional electric utilities to obtain CPCNs for major AMR or AMI meter investments and distribution grid investments for DA, SCADA or volt/var resources"); *see also* Case No. 2020-00336, *Electronic Application of Meade County Rural Electric Cooperative Corporation for a Certificate of Public Convenience and Necessity to Continue with the Full Deployment Installation of its Automated Metering and Infrastructure Systems*, Order (Ky. PSC Apr. 19, 2021); Case No. 2016-00152, *Application of Duke Energy Kentucky, Inc. for (1) A Certificate of Public Convenience and Necessity Authorizing the Construction of an Advanced Metering Infrastructure; (2) Request for Accounting Treatment; and (3) All other Necessary Waivers, Approvals, and Relief*, (Ky. PSC May 25, 2017) Order.

costs.[51] Such costs will result in an increase in the rates of Bluegrass Water's customers and are significant in the aggregate when compared to Bluegrass Water's plant balances and revenue. Thus, the Commission finds that the proposal to install remote monitoring equipment across Bluegrass Water's systems in Kentucky is not an extension in the ordinary course of business and, therefore, that a CPCN should have been obtained pursuant to KRS 278.020(1).

Discussion of Whether to Grant a CPCN

To obtain a CPCN, a utility must demonstrate a need for such facilities and an absence of wasteful duplication.[52]

"Need" requires:

> [A] showing of a substantial inadequacy of existing service, involving a consumer market sufficiently large to make it economically feasible for the new system or facility to be constructed or operated.
>
> [T]he inadequacy must be due either to a substantial deficiency of service facilities, beyond what could be supplied by normal improvements in the ordinary course of business; or to indifference, poor management or disregard of the rights of consumers, persisting over such a period of time as to establish an inability or unwillingness to render adequate service.[53]

As noted above, "wasteful duplication" is defined as "an excess of capacity over need" and "an excessive investment in relation to productivity or efficiency, and an

[51] Freeman Testimony.

[52] *Kentucky Utilities Co. v. Pub. Serv. Comm'n.*, 252 S.W.2d 885 (Ky. 1952).

[53] *Id.* at 890.

unnecessary multiplicity of physical properties."[54] To demonstrate that a proposed facility does not result in wasteful duplication, we have held that the applicant must demonstrate that a thorough review of all reasonable alternatives has been performed.[55] The fundamental principle of reasonable least-cost alternative is embedded in such an analysis. Selection of a proposal that ultimately costs more than an alternative does not necessarily result in wasteful duplication.[56] All relevant factors must be balanced.[57]

<u>Airview</u>

Bluegrass Water reported that the Airview wastewater treatment facility was in poor condition at the time of acquisition and showed clear signs the previous owner had failed to properly operate or reinvest in the plant and facilities.[58] 21 Design, Bluegrass Water's third party engineering firm, inspected Airview's facilities, identified a number of deficiencies at Airview that needed to be corrected, and recommended certain projects to correct those deficiencies.[59] Bluegrass Water then entered into an Agreed Order with the Energy and Environment Cabinet (EEC) that, among other things, required Bluegrass

[54] *Id.*

[55] Case No. 2005-00142, *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for the Construction of Transmission Facilities in Jefferson, Bullitt, Meade, and Hardin Counties, Kentucky* (Ky. PSC Sept. 8, 2005).

[56] *See Kentucky Utilities Co. v. Pub. Serv. Comm'n*, 390 S.W.2d 168, 175 (Ky. 1965). *See also* Case No. 2005-00089, *Application of East Kentucky Power Cooperative, Inc. for a Certificate of Public Convenience and Necessity for the Construction of a 138 kV Electric Transmission Line in Rowan County, Kentucky* (Ky. PSC Aug. 19, 2005).

[57] Case No. 2005-00089, *East Kentucky Power Cooperative, Inc.* (Ky. PSC Aug. 19, 2005), final Order at 6.

[58] Cox Testimony at 7.

[59] *See* Response to Staff's Second Request, Item 27, 2 PSC 27 Engineering Memos Unredacted.pdf at JA 00180-JA 00183.

Water to file a corrective action plan (CAP) describing how it would cure the deficiencies identified in 21 Design's engineering report.

In its application, Bluegrass Water proposed the following repairs and upgrades to Airview's wastewater treatment facilities.

Construction Item		Estimated Cost
Install flow equalization storage (20,000 gal)	$	55,000
Influent Pumps from flow eq	$	15,000
Chainlink fence replacement	$	25,000
Sludge Holding tank renovation	$	5,000
Clarifier Repairs	$	205,000
Replace diffusers in aeration tankage	$	30,000
Replace RAS lines from clarifier	$	15,000
Replace blower	$	25,000
Replace effluent pipe	$	15,000
Remove contact chamber from creek	$	5,000
Access road repair	$	15,000

The proposed construction items are consistent with the needs identified by 21 Design in its engineering report, the recommendations made by 21 Design in its report, and the proposals 21 Design made to the EEC on behalf of Bluegrass Water in its CAP.[60] Further, while alternatives to each construction item were not specifically discussed, alternatives appear to have been reviewed where appropriate.[61] Moreover, the Commission understands that previous efforts by the previous owners to connect Airview to Elizabethtown's system, facilitated by the EEC and the Commission, failed. Thus, the Commission finds that the projects identified above are both needed and will not result in

[60] *See* Response to Staff's Second Request, Item 3, 2-PSC-03-AOs.pdf, 2-PSC-03_Correspondence.pdf, 2-PSC-03_CAPs.pdf; Response to Staff's Second Request, Item 27, 2 PSC 27 Engineering Memos Unredacted.pdf at JA 00180-JA 00183.

[61] *See e.g.,* Response to Staff's Second Request, Item 3, 2-PSC-03_Correspondence.pdf, 2-PSC-03_CAPs.pdf; Response to Staff's Second Request, Item 27, 2 PSC 27 Engineering Memos Unredacted.pdf, JA 00180-JA 00183.

wasteful duplication[62] and, therefore, that a CPCN should be granted for those portions of the projects that are not complete.

However, Bluegrass Water indicated at the hearing and in response to post-hearing request for information that work on most of the construction items identified was completed, which means that Bluegrass Water violated KRS 278.020(1) by failing to obtain a CPCN before it began construction on those items. The Commission will not grant a CPCN for construction that has been completed,[63] and by failing to obtain a CPCN, a utility risks a finding by the Commission barring recovery of the investment. The Commission declines to do so here, given the urgent need for the construction and the absence of wasteful duplication. However, in the future, Bluegrass Water should be aware that the Commission may exercise its discretion to penalize or bar recovery of capital costs on plant for which a utility failed to obtain a CPCN as required.

<u>Brocklyn System</u>

Bluegrass Water reported that the Brocklyn system was in poor condition at the time of acquisition and exhibited signs of past mismanagement, poor operation practices, and an overall lack of investment.[64] Among other things, Bluegrass Water indicated that:

> All steel tanks and plant components were severely corroded, and many treatment components had not been properly

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[62] This is especially true given that the actual cost of some of the projects was significantly lower than the estimated cost. *See* Bluegrass Water's response to the Attorney General's Post-Hearing Request for Information (Response to Attorney General's Post Hearing Request), Item 1, AG_post-hearing_DR01 (indicating that the final cost of the Clarifier Repairs was only $5,471.00 and that the final cost to Replace Blower was only $7,230).

[63] *See* Case No. 2003-00495, *Application of Classic Construction, Inc. for Approval of Transfer of Ownership of Collbrook Sewage Treatment Plant in Franklin County, Kentucky from Aquasource Utility, Inc.*, (Ky. PSC May 10, 2004) Order (The Commission will not issue a CPCN for construction that has been completed prior to a request for a CPCN.).

[64] Cox Testimony at 14.

> maintained. Yard piping consisted of PVC and flexible lines placed above ground, when proper installation of such facilities requires them to be buried. . . . Stormwater from an uphill neighborhood was routed into an open dirt channel running between the lagoon and an on-site package treatment plant, resulting in severe erosion that threatened the structural integrity of the lagoon further putting the surrounding community at risk.[65]

21 Design inspected Brocklyn's facilities, identified a number of deficiencies at Brocklyn's wastewater treatment plant, and recommended certain repairs and upgrades to correct those deficiencies. Bluegrass Water then entered into an Agreed Order with the EEC that, among other things, required Bluegrass Water to file a CAP describing how it would cure the deficiencies identified in 21 Design's engineering report.

At Brocklyn, Bluegrass Water indicated that it closed the lagoon of the current treatment facility (though in its CAP and updates to EEC it referred to it as a clean out of the lagoon), made repairs to the sludge judge lagoon cell, and cleaned up sludge from the creek surrounding Brocklyn's sewage treatment plant.[66] Bluegrass Water had also initially proposed a number of repairs to its existing plant.[67] However, in a July 29, 2020 revision to its Brocklyn CAP, Bluegrass Water reported to the EEC that in the process of making repairs to the system that it determined that the tankage of the Brocklyn extended aeration plant is severely deteriorated such that the plant at Brocklyn would need to be

[65] *Id.*

[66] Response to Attorney General's Post Hearing Request, Item 1, AG_post-hearing_DR01; *see also* Response to Staff's Second Request, Item 3, 2-PSC-03_Correspondence.pdf (containing updates discussing Bluegrass Water's actions to comply Brocklyn's CAP).

[67] Response to Staff's Second Request, Item 3, 2-PSC-03_CAPs.pdf (containing Bluegrass Water's initial CAP for Brocklyn).

replaced.[68] Bluegrass Water is now proposing to replace the wastewater treatment facility at Brocklyn in lieu of other proposed repairs[69] and estimated the cost of the plant would be $650,000.[70]

The evidence indicates that there is a need to take action at Brocklyn to repair a significant issue with the existing plant, and Bluegrass Water did explore some alternatives to building a new package treatment plant in that it was initially attempting to simply repair the system.[71] However, while Bluegrass Water indicated its belief that connecting to the city of Richmond's sewer system would be more costly, Bluegrass Water acknowledged at the hearing that it had not fully weighed the feasibility or the cost of attaching the Brocklyn's collection to the city of Richmond's facilities.[72] Bluegrass Water indicated that it was currently in the process of completing that analysis, which EEC had requested from Bluegrass Water as part of the permitting process for the new plant proposed at Brocklyn.[73] The Commission finds that Bluegrass Water has not yet explored all reasonable alternatives with respect to the proposed new sewage treatment plant at Brocklyn and, therefore, that the required CPCN should be denied without

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[68] Response to Staff's Second Request, Item 3, 2-PSC-03_Correspondence.pdf (containing the July 29, 2020 letter).

[69] *Id.*

[70] Response to Staff's Second Request, Item 3, 2PSC12-03_RateBase(Brocklyn).xlsx at Tab CWIP – BY B4.

[71] Response to Staff's Second Request, Item 3, 2-PSC-03_Correspondence.pdf (containing the July 29, 2020 letter); Response to Staff's Second Request, Item 3, 2-PSC-03_CAPs.pdf (containing Bluegrass Water's initial CAP for Brocklyn in which it was initially proposing to repair the treatment plant); Response to Staff's Second Request, Item 3, 2-PSC-03_Correspondence.pdf (containing the July 29, 2020 letter in which Bluegrass indicated that it would need to repair the plant).

[72] May 20, 2021 H.V.T at 11:20:05-11:22:18.

[73] May 20, 2021 H.V.T at 11:20:05-11:22:50.

prejudice. Bluegrass Water should refile the request when it has explored all reasonable alternatives.

Delaplain System

Bluegrass Water did not own the Delaplain system at the time that the application in this matter was filed, but Bluegrass Water reported that it had identified a number of problems with the system as part of its preliminary due diligence to purchase the system that it contended must be addressed immediately after closing and within the period covered by the forecasted test year.[74] Bluegrass Water indicated that the primary issue facing the facility is that "flows massively exceed its design capacity," which Bluegrass Water stated indicates that the facility is undersized and needs to be expanded to treat the high volume waste loading the facility receives rather than just attempting to reduce infiltration and inflow of the system.[75] Bluegrass Water proposed to convert and expand the waste water treatment plant at an estimated cost of over $800,000 to address that capacity shortfall as well as other issues identified with the Delaplain system.[76]

Bluegrass Water indicated that discussions with the City of Georgetown regarding Georgetown's ability to take waste from Delaplain, as opposed to increasing capacity at the treatment plant, are ongoing.[77] Bluegrass Water indicated that there were some preliminary discussions with Georgetown before Bluegrass Water purchased the Delaplain system and that Delaplain's engineering firm reached out for more formal

[74] Freeman Testimony at 44.

[75] Freeman Testimony at 45; *see also* Response to Staff's Second Request, Item 27, 2 PSC 27 Engineering Memos Unredacted.pdf; May 19, 2021 H.V.T at 9:39:50.

[76] Freeman Testimony at 44-46;

[77] *See* May 20, 2021 H.V.T at 11:15:15.

discussions in about March of 2021.[78] Bluegrass Water indicated that the discussions are ongoing and that Georgetown is preparing a proposal with the details of what Delaplain would have to do to connect to Georgetown's systems.[79] Bluegrass Water did not have a specific timetable regarding when it would receive a proposal from the city but at the time of the hearing indicated that they expected it within a month.[80]

While the Commission understands that Bluegrass Water anticipates that the cost of connecting to Georgetown's system will be more than simply expanding its own plant, Bluegrass Water is still waiting on Georgetown's proposal, and the analysis of wasteful duplication and the reasonable least cost alternative is not simply about the capital cost of the project. In this instance, the Commission finds that Bluegrass Water cannot establish the absence of wasteful duplication with respect to the expansion at the Delaplain system until it has received and evaluated the proposal from Georgetown. Thus, the Commission finds that the CPCN for the proposed treatment plant conversion and expansion at Delaplain should be denied without prejudice.

River Bluffs System

Bluegrass Water reported that River Bluffs has a long history of non-compliance with environmental regulations and that maintenance at the facility had been poor.[81]

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[78] May 20, 2021 H.V.T at 11:17:28.

[79] *See* May 20, 2021 H.V.T at 11:15:15.

[80] *See* May 20, 2021 H.V.T at 11:15:15.

[81] Cox Testimony at 56–58.

Bluegrass Water indicated in testimony filed with the application in this matter that the following repairs and improvements would be necessary:[82]

Construction Item		Estimated Cost
Address Inflow and Infiltration	$	25,000.00
Mission Monitoring	$	18,000.00
Lift station cleanup	$	33,000.00
Control Panel Replacement	$	10,000.00
Replace influent/exposed PVC pipe	$	10,000.00
Treatment facility cleanup and repair	$	20,000.00
Replace diffusers and blowers	$	32,500.00
Replace air header	$	5,000.00
Replace sludge returns	$	10,000.00

Bluegrass Water noted that it had only recently closed on its acquisition of the River Bluffs system and that many of the planned improvements had not been completed, but Bluegrass Water noted that "items such as basic site cleanup and the proper installation of the influent line have been completed" and that "[r]epairs and patching of corroded steel tankage are underway and continue."[83]

Bluegrass Water presented an engineering report that generally supported the need for the proposed construction items. The evidence for the construction as proposed supported the need and the absence of wasteful duplication.[84] Thus, while the Commission could not grant a CPCN for work that had already been completed, it could allow Bluegrass Water to recover the cost of the projects through rates as it did for the projects Bluegrass Water completed at Airview without obtaining a CPCN.

[82] Freeman Testimony at 33–34.

[83] Freeman Testimony at 33.

[84] Response to Staff's Second Request, Item 27, 2 PSC 27 Engineering Memos Unredacted.pdf (containing River Bluffs Report); Response to Staff's Second Request, Item 3, 2-PSC-03_Correspondence.pdf, 2-PSC-03_CAPs.pdf.

However, in response to post hearing requests for information from the Attorney General, Bluegrass Water indicated that several of the construction items proposed were significantly over budget. Specifically, Bluegrass Water indicated that the treatment facility cleanup and repair cost $231,579 to complete despite an estimated cost of $20,000; the replacement of diffusers and blowers cost $96,559 to complete despite an estimated cost of $32,500; and the replacement of the air header cost $35,000 to complete despite an estimated budget of $5,000.

While projects may occasionally go over budget, the extent by which the construction items identified above went over budget indicate that the work completed does not represent the same work initially contemplated. Further, the CAP for River Bluffs, which Bluegrass Water used to justify the construction, and correspondence between Bluegrass Water and the EEC do not indicate a significant change in the scope of the work.[85] Bluegrass Water has also indicated it is contemplating a new plant at River Bluffs,[86] such that any repairs made at this time may not provide long term benefits to customers. Thus, based on the current record, the Commission is not able to find that the repairs and upgrades that resulted in the construction items being significantly over budget are needed and will not result in wasteful duplication.

Based on the finding above, the Commission will adjust Bluegrass Water's rate base below based on the extent those construction items went over budget. However,

[85] *See* Response to Staff's Second Request, Item 3, 2-PSC-03_Correspondence.pdf, 2-PSC-03_CAPs.pdf.

[86] *See* Response to Staff's Second Request, Item 3, 2-PSC-03_CAPs.pdf (where Bluegrass Water stated in a July 30, 2020 CAP for River Bluffs that "[f]ollowing these initial improvements, a period of observation and evaluation will be conducted to determine if a process change is needed at the facility to consistently meet limits that the facility has struggled with in the past"); *see also* Response to Staff's Second Request, Item 27, 2 PSC 27 Engineering Memos Unredacted.pdf (containing River Bluffs Report).

for the reasons Bluegrass Water is being allowed to recover its investment in Airview, the Commission may allow Bluegrass Water to recover the amounts excluded from River Bluffs here as part of a subsequent rate case if Bluegrass Water later establishes, as part of that case, that the additional costs were for capital spending at River Bluffs that was needed and did not result in wasteful duplication.

Implementation of Remote Monitoring

Bluegrass Water installed or proposed to install remote monitoring equipment at most of its systems. In response to the Attorney General's First Request for Information, Item 6, Bluegrass Water explained that remote monitoring is necessary, because it "increases the effectiveness of operations at basic sewage plants and collection systems and drives down costs related to improvements and environmental compliance that would otherwise be passed through to customers." However, while remote monitoring does appear to provide more continuous access to data than having an operator inspect the systems daily, as required by 807 KAR 5:071, Section 7(4), the remote monitoring systems, at least in part, serve the same purpose as that requirement by ensuring that a utility is constantly monitoring the performance of equipment to prevent failures and ensure adequate service. Bluegrass Water indicated that operator costs in Kentucky were higher than those for Bluegrass Water affiliates in other states precisely because it required its operators to comply with 807 KAR 5:071, Section 7(4), which is not required in other states, such that the benefits of remote monitoring in Kentucky are at least reduced. Finally, Bluegrass Water acknowledged that it had not performed any cost benefit analysis of the installation of the monitoring equipment in Kentucky.[87] Because, the costs of remote monitoring are not immaterial,[88] the Commission finds that Bluegrass Water failed to establish the absence of wasteful duplication.

Additional Construction

Pursuant to 807 KAR 5:001, Section 19(1), the Commission may, in its discretion, issue a declaratory order with respect to . . . the applicability to a person, property, or state of facts of an order or administrative regulation of the commission or provision of KRS Chapter 278." While the Commission may choose to exercise its discretion and address an application for a declaratory order, it may similarly choose not to address an application for a declaratory order. This regulation is primarily intended as a mechanism to provide utilities guidance in situations involving new or novel issues that might be difficult to resolve through construction of the Commission's orders or regulations, or KRS Chapter 278.

A number of utilities have been abusing 807 KAR 5:001, Section 19 recently by failing to request a CPCN where one is clearly required and instead requesting an order from the Commission that a CPCN is not required or by requesting a declaratory order that all proposed spending in a given period does not require a CPCN and requesting a CPCN in the alternative. The declaratory order regulation is not intended to resolve such issues. Rather, an application for a CPCN should be filed where a CPCN is obviously required, an application for a declaratory order should only be filed where there is a

[87] May 19, 2021 H.V.T at 09:45:00.

[88] The capital costs ranged from about $7,500 to $50,000 per system; Bluegrass Grass indicated that the equipment would last 5 to 10 years; and there is a monthly subscription fee per system.

legitimate question regarding whether a CPCN is required, and utilities should not routinely request that the Commission review all spending in a given period to determine what does and does not require a CPCN.

Here, as noted above, Bluegrass Water claimed in its application that no CPCN was required despite proposing approximately $7.5 million in capital spending, including projects to replace or significantly upgrade existing wastewater treatment plants. Bluegrass Water's claims that no CPCN is required for the new plant at Brocklyn or the expansion at Delaplain, which it backed away from in testimony, are absurd on their face. Further, it should have been clear, between precedent and a plain reading of the law, that the additional construction discussed above required a CPCN. Thus, Bluegrass Water should not have requested a declaratory order or in the alternative requested a CPCN, but rather, should have specifically requested a CPCN for the projects that required it.

The Commission could have simply exercised its discretion and declined to address the application for the declaratory order and, in turn, the application for a CPCN. The Commission did not do so here for the projects discussed above, because Bluegrass Water is not the only utility that has recently engaged in this practice. However, while the construction items not specifically addressed above appear to be necessary and do not appear to result in wasteful duplication, the Commission does decline to make a specific finding that each additional construction item not discussed above is an extension in the ordinary course of business. Further, in the future, if Bluegrass Water or another utility files an application for a declaratory order finding that a CPCN is not required where one is clearly required or that all proposed spending does not require a CPCN, the Commission may decline to address any part of the application and, in turn, refuse to grant any alternative application for a CPCN even where a CPCN is clearly necessary, which may be considered in denying a utility recovery the cost of such plant in the future.

RATES

Legal Standard

Bluegrass Water filed its application for a rate adjustment pursuant to KRS 278.180 and KRS 278.190. The Commission's standard of review of a utility's request for a rate increase is well established. In accordance with statutory and case law, Bluegrass Water is allowed to charge its customers "only 'fair, just, and reasonable rates."[89] Further, Bluegrass Water bears the burden of proof to show that the proposed rate increase is just and reasonable, under KRS 278.190(3).

Test Period

Bluegrass Water proposed the 12 months ending April 30, 2022, as its forecasted test period to determine the reasonableness of its proposed rates.[90] The Attorney General and Joint Intervenors did object to the proposed test period for the reasons discussed above and requested that a historical test period be used for some of the systems, but as discussed above, the Commission did not find that their objections justified rejecting the forecasted test period. For the reasons discussed above and based on the record in this matter, the Commission finds Bluegrass Water's forecasted test period to be reasonable and consistent with the provisions of KRS 278.192 and 807 KAR 5:001, Section 16(6), (7), and (8). Therefore, the Commission will accept the forecasted test year proposed by Bluegrass Water for use in this proceeding.

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[89] KRS 278.030; and *Pub. Serv. Comm'n v. Com. ex rel. Conway*, 324 S.W.3d 373, 377 (Ky. 2010).

[90] Application at 4.

VALUATION

Sewer Rate Base

Bluegrass Water proposed a forecasted net investment rate base for its sewer division of $6,907,546 based on a 13-month average for that period.[91] In its base period update, Bluegrass Water increased its proposed sewer rate base to $7,689,482.[92] As discussed in more detail below, the Commission does not believe Bluegrass Water's rate base numbers are credible. Rather, the Commission finds that Bluegrass Water's net investment sewer rate base in the forecasted test period, excluding the 00297 systems, is $2,601,721, as shown below.

Utility Plant In Service (UPIS)

Bluegrass Water reported a base year sewer UPIS ending balance of $4,305,222.[93] According to Bluegrass Water, its base year UPIS balance reflected the actual amounts recorded on its books as of August 31, 2020, and the forecasted UPIS additions for the four-month period ending December 31, 2020.[94] Bluegrass Water explained that its 13-month average UPIS of $8,438,874 in the forecasted period was calculated by adding forecasted acquisitions and plant additions and subtracting forecasted retirements through April 2022.[95]

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[91] Responses to Staff's First Request, Item 1, BGUOC2020RateCase-RateBase_(Sewer).xlsx, Tab FY Rate Base - Sewer B1.

[92] Base Period Update (filed Mar. 19, 2021), Excel Workbook: BYupdate-RateBase_(Sewer).xlsx, Tab FY Rate Base - Sewer B1.

[93] Response to Staff's First Request, Item 1, BGUOC2020RateCase-RateBase_(Sewer).xlsx, Tab UPIS - BY B2.

[94] Application, Exhibit 8, Thies Direct Testimony at 13.

[95] *Id.*

Joint Intervenors noted that Bluegrass Water had committed to account for its plant retirements through the forecasted test year.[96] Upon review of Bluegrass Water's filing of its base year updates, Joint Intervenors argue that Bluegrass Water had not recorded UPIS retirements in either the base period or the forecasted test year.[97] Joint Intervenors argue that Bluegrass Water's lack of attention to detail is not credible and is unacceptable for a regulated utility.[98]

Joint Intervenors also note that Bluegrass Water asserted in its application that it would invest approximately $7.56 million ($6.4 million in its wastewater division and $1.16 million in its water division) and that it would complete that investment prior to the end of the forecasted test year on April 30, 2022. However, Joint Intervenors point out that Bluegrass Water identified less than $2 million that has actually been spent on construction across Bluegrass Water's entire system.[99]

The Attorney General similarly notes that Bluegrass Water's witness, Brent Thies, under questioning from Vice-Chairman Chandler at the hearing, testified that Bluegrass Water failed to reflect any plant retirements in developing its Forecasted Test-Year UPIS.[100] The Attorney General claims that Bluegrass Water failed to determine if plant

[96] Joint Intervenors Brief at 10.

[97] *Id.* at 10–11.

[98] *Id.* at 11.

[99] *Id.*

[100] Brief of the Attorney General at 4–5.

retirements were appropriate and that such an incomplete analysis would inflate Bluegrass Water's revenue requirement to the detriment of ratepayers.[101]

According to Bluegrass Water, both intervenors assert that there must have been retirements from UPIS and that UPIS retirements must be included as net subtractions in the base or forecasted test year schedules.[102] Bluegrass Water argues that neither the Attorney General nor Joint Intervenors acknowledge or address the explanation that was given in the hearing by Brent Thies that the lack of plant retirements in the designated columns was not material due to offsetting accumulated depreciation.[103] Joint Intervenors argue that Bluegrass Water lacks the accounting records necessary to demonstrate that the claim presented by Mr. Thies at the hearing is accurate.[104]

With respect to Joint Intervenors assertion that Bluegrass Water has spent under $2 million on construction that could be reflected as additions across the entire system, Bluegrass Water argues that the data request and response cited in support of that statement relate to the planned projects itemized in Mr. Freeman's direct testimony that were partially or fully complete at the time of his hearing testimony, not expenditures for projects on the entire Bluegrass Water system since September 2019.

The Commission agrees with the Joint Intervenors and the Attorney General regarding the lack of supporting evidence for Bluegrass Water's UPIS. First, schedules and spreadsheets provided by Bluegrass Water include conflicting information. As noted

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[101] *Id.*

[102] Bluegrass Water's Brief at 11.

[103] *Id.* at 11–12.

[104] Joint Intervenors' Brief at 9.

above, Bluegrass Water calculated the 13-month average of its sewer UPIS in the application and attached schedules as $8,438,874.[105] Then, in responding to a request from Commission Staff, Bluegrass Water provided separate Excel workbooks with the 13-month average rate base for each separate system that it had acquired or was seeking to acquire prior to the beginning of the forecasted period.[106] Upon the Commission's review of the individual system rate bases, it was noted that total UPIS for the 19 systems did not equal the amount reported by Bluegrass Water in its application as shown in the table below.

	UPIS Staff 2nd Request Item 12
Woodland Acres	$ 80,163
Timberland	125,127
Springcrest	49,200
River Bluff	596,176
Randview	139,973
Persimmon Ridge	504,609
Marshell Ridge	60,597
LH Treatment	679,447
Columbia	327,264
Kingswood	367,133
Haven	60,728
Grest Oaks	233,347
Golden Acres	204,283
Fox Run	348,728
Delaplain	2,252,079
Carriage Park	60,408
Brockyln	659,362
Arcadia Pines	46,563
Airview	402,073
UPIS Totals	7,197,260
Application 13-Month Average UPIS and CWIP	(8,438,874)
Difference	$ (1,241,614)

[105] Application, Exhibit 8, Thies Testimony at 13; Response to Staff's First Request, Item 1, Excel Workbook: BGUOC2020RateCase-RateBase_(Sewer).xlsx, Tab UPIS - FY B2.

[106] Responses to Staff's Second Request, Item 12.

This discrepancy raises questions regarding what Bluegrass Water included in UPIS. When Bluegrass Water was asked to provide the system specific information as originally requested in a post hearing request for information, Bluegrass Water stated that "[d]ue to the process used to update rate base numbers at the end of the base period, the data source necessary to produce system level rate base specific numbers is no longer available."[107] Nevertheless, Bluegrass Water attempted to explain the discrepancy by stating:

> A data source was inadvertently omitted from the Utility Plant in Service totals for the system. This data source was CWIP balances that were on the books of Bluegrass Water as of 12/31/2020 but the assets were not yet placed into service.

Bluegrass Water's explanation does not resolve questions regarding what Bluegrass Water included in UPIS, including how CWIP was accounted for and whether the forecasted UPIS has been reported net of Accumulated Depreciation, Plant Acquisition Adjustments, or CIAC. Further, Bluegrass Water's explanation does not provide any way to assess the UPIS Bluegrass Water included in the forecasted period for each system, as filed with its application, in order to check the proposed UPIS and CWIP changes against Bluegrass Water's projected projects.

More problematic, the undisputed evidence indicates Bluegrass Water did not include any retirements in the base period, the forecasted test year, or the period between the base and forecasted periods despite providing sworn testimony with its application

[107] Responses to Staff's Hearing Data Request, Item 1.a.

that it had done so.[108] As Bluegrass Water acknowledged, changes to UPIS are calculated in a given period by taking the starting balance of the UPIS, adding the additions, and then subtracting the retirements such that the net change is reflected at the end of the period.[109] Moreover, it is clearly understood and expected that if a utility is projecting that it will incur significant capital costs to repair, replace, and upgrade existing plant that it will have retirements. When asked to explain why Bluegrass Water did not account for retirements, Bluegrass Water's witness stated that he did not really have an explanation except that some, or most, existing assets were fully depreciated such that Bluegrass Water recognized the "negligible" impact the retirements would have on plant in service and, therefore, did not focus on projecting retirements.[110] However, by calculating UPIS in that manner, Bluegrass Water focused solely on the positive side of equation that will increase UPIS, while ignoring any change to the negative side of the equation that might decrease UPIS. In short, Bluegrass Water essentially testified at the hearing that it focused on projecting amounts that increased its projected UPIS and, therefore its revenue requirement, while ignoring the component that would decrease the UPIS.

Bluegrass Water claimed at the hearing and in its brief that its failure to account for retirements had minimal or no effect on rates, because the existing plant of the systems it purchased had largely been depreciated and, therefore, that property

[108] May 19, 2021 H.V.T. at 15:45:33, 16:39:00; 16:44:00; *see also* Response to Staff's Second Request, Item 5 and 7, 2-PSC-05b.xlsx, 2-PSC-07b.xlsx (showing no retirements during any of the relevant periods).

[109] *See* May 19, 2021 H.V.T. at 16:37:50-16:40:24.

[110] *See* May 19, 2021 H.V.T at 16:39:25.

Bluegrass Water should have retired was being offset by accumulated depreciation, which would be eliminated when the plant was retired, such that its failure to include retirements had no net effect on rates. However, Bluegrass Water's explanation falls apart for two reasons. First, while it appears that some of the systems Bluegrass Water purchased were fully depreciated,[111] all of the systems were not fully depreciated such that some assets with a net plant balance likely would be retired given the scope of the work Bluegrass Water was proposing. Second, Bluegrass Water calculated depreciation expense in the base and forecasted periods by applying depreciation rates to its UPIS[112] and, therefore, Bluegrass Water's model would include depreciation expense on UPIS that should have been retired even if that UPIS is fully offset in rate base by corresponding accumulated depreciation.[113] Thus, Bluegrass Water's failure to project retirements of UPIS during any period from at least January 1, 2020, through April 30, 2022, when it was engaging in significant capital spending did materially impact rates.

Bluegrass Water's failure to account for retirements in projecting UPIS and other discrepancies in its rate base schedules place the Commission in a difficult position in attempting to set a rate base to which a rate of return and depreciation rates should apply

[111] There is no evidence in the record regarding the extent to which the assets of the systems were depreciated when Bluegrass Water purchased them. Commission Staff requested in a post hearing request for information that Bluegrass Water provide the original cost of the acquired assets of each system along with the associated accumulated depreciation by NARUC account. Bluegrass Water provided the plant balances projected for the end of the forecasted period and the projected accumulated depreciation for the end of the forecasted period. *See* Response to Staff's Post-hearing Request, Item 2. However, in response to Joint Intervenors' post hearing request for information, Bluegrass Water did provide the rate base of each system at the time of acquisition, which indicated that that most of the systems had little to no rate base. *See* Response to Joint Intervenors' Post-Hearing Request, Item 12, INTphDR12a.xlsx.

[112] *See* Response to Staff's First Request, Item 1, BGUOC2020RateCase-RateBase_(Sewer).xlsx, Tab Dep - FY B3.1 (showing that depreciation expense for a particular account is calculated by multiplying the utility plant in service balance by the depreciation rate).

[113] *See* May 20, 2021 at 09:22:23–09:25:30.

when setting rates. As Bluegrass Water acknowledged, the original cost of the assets for many of the systems Bluegrass Water purchased in this matter were fully depreciated when Bluegrass Water purchased them. However, assuming depreciation was properly tracked by the previous owners, limited portions of some systems were not fully depreciated at the time the systems were transferred to Bluegrass Water.[114] The problem is that the evidence regarding UPIS and accumulated depreciation for each sewer system at the time of transfer is limited, and there is no specific evidence in the record regarding the portions of the UPIS for each sewer system at the time of transfer that should have been retired as Bluegrass Water made projected repairs, replacements, and improvements, because Bluegrass Water did not project any retirements.

Bluegrass Water did provide some consideration to the previous owners of the systems at issue for the systems' assets. However, Bluegrass Water did not propose or present evidence in support of a system acquisition adjustment in this matter to recover those acquisition costs to the extent they exceeded the net value book value of the systems.[115] In fact, although related cases indicate that the acquisition costs for the systems at issue in this matter were limited, there was limited to no evidence regarding the consideration provided to purchase the assets of the systems at issue.[116]

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[114] Again, the system specific schedules did not match the system wide schedules filed with the application. Bluegrass Water did not response to Commission Staff's post hearing request for information asking for the original cost of the acquired assets and associated accumulated depreciation by NARUC account. *See* Response to Staff's Post-Hearing Request, Item 2.

[115] May 20, 2021 H.V.T. at 09:15:30.

[116] The only evidence as to purchase prices identified by the Commission was anecdotal. For instance, at the hearing, when Bluegrass Water was discussing why its failure to account for retirements had little effect, it displayed and discussed a journal entry for Brocklyn indicating that the total payments at closing were $14,350.90. May 20, 2021 H.V.T. at 09:11:40, Exhibit 2. Similarly, in response to Commission Staff's Third Request, Item 3, Bluegrass Water provided the sales contract for the LH Treatment Company, LLC in support of an O&M expense and that contract contained the sale price of $230,000.

For the reasons discussed above and being otherwise sufficiently advised, the Commission finds that Bluegrass Water failed to establish the existing UPIS and accumulated depreciation for the systems at issue in this matter at the time of acquisition and the extent to which those assets should have been retired during the base period, the forecast period, and the period between the base and the forecasted period. The Commission observes that intervenors suggest that the Commission should dismiss this matter, in part, due that failure and that is a potential solution. However, the Commission finds that such a solution would not be in the long term interest of Bluegrass Water or its customers given Bluegrass Water's financial position and the need to attract additional capital to provide service and necessary upgrades to systems that have seen little investment in many years. Instead, the Commission will remove any UPIS and accumulated depreciation associated with the systems at the time of the acquisitions in this matter. To accomplish this, the Commission will calculate UPIS by simply adding the original cost of the projects Bluegrass Water indicated it had completed or would complete in 2019, 2020, the forecasted period, and the period between the base period and the forecast period and will calculate accumulated depreciation by eliminating accumulated depreciation prior to the forecasted period, which would nearly all be attributed to depreciation that occurred prior to Bluegrass Water's acquisitions of the various systems.

Specifically, with respect to the UPIS, the Commission will use the spreadsheet provided by Bluegrass Water in response to Commission Staff's Second Request, Item 6. In response to that request, Bluegrass Water provided a spreadsheet, at the end of February 2021, with the total actual cost of each project, if completed, or the total expected cost of each project that Bluegrass Water contends supports that projected additions or CWIP in the schedules filed with the application for the base period, the forecasted period, and the months between the base and the forecasted periods, as well as the date on which work on each project began or is expected to begin and the date on which each project was placed in service or is expected to be placed in service.[117]

The Commission submits that the information provided in response to Staff's Second Request, Item 6, should reflect, by Bluegrass Water's own admission, all projects that support additions to UPIS in the period from January 1, 2020, about four months after Bluegrass Water began operating any of the systems, through the end of the forecasted period. The Commission notes that spreadsheet also justifies the spending by referring to both Mr. Cox and Mr. Freeman's testimony, which supports the finding that it includes actual or projected spending discussed by both witnesses. Bluegrass Water also provided the actual and projected dates on which its proposed spending would begin and the actual or projected in service dates such that it is possible to determine when projects should be moved from CWIP to UPIS and, using Bluegrass Water's straight-line method for projecting CWIP spending,[118] when projected spending will occur during the forecasted period in order to calculate the 13-month average of CWIP and UPIS.

The issue with the using the information provided in response to Staff's Second Request, Item 6 is that Bluegrass Water apparently failed to include the projects for Persimmon Ridge and arguably there could have been spending on projects that occurred in 2019 that would not be include with that information. To address the issue of the

[117] Response to Staff's Second Request, Item 6, 2-PSC-06.xlsx.

[118] *See* May 20, 2021 H.V.T. at 12:01:54–12:02:38 (in which Mr. Duncan states that CWIP during forecasted period was projected based on a straight line of the remaining projected spending and the project end date).

Persimmon Ridge projects, the Commission will use the construction information provided in Mr. Freeman's testimony for Persimmon Ridge, which was largely complete as of the date of the hearings, and a final in service date for the Persimmon Ridge construction of September 2021 based on the final in service dates of the other systems included therein. To address construction in 2019, the Commission will only include construction for which there is evidence it was actually completed in 2019 in Bluegrass Water's response to the Attorney Generals post-hearing request for information.[119]

Using the method discussed above, and removing any construction for the 00297 systems, the 13-month average UPIS balance calculated by the Commission as shown in Appendix A is $1,719,678. That UPIS balance is $6,719,196 below the UPIS balances projected by Bluegrass Water in the forecasted period. However, the Commission notes that it is making this adjustment, in part, because Bluegrass Water failed to meet its burden with respect to amounts removed, including UPIS and accumulated depreciation at the time of transfer and the extent to which those amounts should have been retired. This Order should not be construed as preventing Bluegrass Water from seeking to include those amounts, should it choose to do so, in rate base in a future rate proceeding with proper supports.

Construction Work In Progress (CWIP). Bluegrass Water defines CWIP as the value of utility plant that is under construction but has not yet been placed into service.[120] Bluegrass Water's forecasted CWIP of $877,758 is based on a thirteen-month average

[119] Response to Attorney General's Post-Hearing Request, Item 1, AG_post-hearing_DR01.xlsx, Tab Construction Invoices (showing $298,830 in spending in 2019).

[120] Application, Exhibit 8, Thies Testimony at 13.

of the forecasted balances from April 1, 2021, through April 30, 2022.[121] Using the construction completed in the forecasted test-year and excluding CWIP for the 00297 systems, as discussed above for UPIS, the Commission calculated a 13-month average CWIP in the forecasted period of $761,724, which is $116,034 below Bluegrass Water's forecasted CWIP. The Commission's calculation of its 13-month average CWIP is included in Appendix A.

Brocklyn Plant Replacement. As noted above, the Commission denied the CPCN for the Brocklyn plant replacement at this time. Bluegrass Water projected the cost of the plant replacement would be approximately $650,000.[122] The Commission removed that project from CWIP and UPIS by removing $650,000 from the total projected budget for Brocklyn shown in response to Staff's Second Request, Item 6. The Commission then included the remainder of the projected budget in UPIS as shown in Appendix A.

River Bluffs Plant Project. As noted above, the Commission denied a CPCN for three projects at River Bluffs with an original projected cost of $57,500.00 to the extent that they were over budget by $305,638 and found that Bluegrass Water failed to establish the need for that expanded project or the absence of wasteful duplication. Based on total costs reflected for River Bluffs in response to Staff's Second Request, Item 6 as compared to the original budget in Mr. Freeman's testimony, the Commission finds that those additional costs were included in the response and, therefore, must be adjusted here based on the findings discussed above. Thus, as shown in Appendix A, the Commission

[121] *Id.*

[122] Response to Staff's Second Request, Item 3, 2PSC12-03_RateBase(Brocklyn).xlsx at Tab CWIP–BY B4.

removed that amount from UPIS and CWIP for the River Bluffs system when calculating the 13-month average discussed above.

Canceled Construction Items. Bluegrass Water's witness testified at the hearing that in consultation with the their third party engineering firm that Bluegrass Water had decided to eliminate several projects at Lake Columbia just prior to the hearing. Specifically, he stated that they had decided to eliminate the flow equalization and pumping system item with a projected cost of $40,000, the install aeration in flow equalization and sludge holding item with a projected cost of $15,000, and the collection system repair for I&I item with a projected cost of $30,000. Since Bluegrass Water indicated that those projects had been eliminated just prior to hearing, the Commission finds that the projected cost of those projects that were included in the costs Bluegrass Water projected would now not be spent at Lake Columbia through the forecasted period as indicated in response to Staff's Second Request, Item 6. Thus, the Commission adjusted the cost of those projects out of CWIP and UPIS for Lake Columbia as shown in Appendix A.

Monitoring Systems. According to the Joint Intervenors, Bluegrass Water is paying a single contractor – Midwest Water Operations, LLC (Midwest) for having a technician visit each system on a daily basis while installing expensive mission control remote monitoring devises.[123] Joint Intervenors add that Bluegrass Water is also paying for the expenses associated with the Mission control subscription and the cost of Midwest's daily

[123] Brief of the Joint Intervenors at 14.

visits.[124] Joint Intervenors explains that this results in recovery of unnecessarily duplicative costs and the Commission should disallow either the capital or monitoring expenses associated with the mission control system or the costs of Midwest's daily visits.[125]

As discussed in more detail above, the Commission agreed with the argument presented by Joint Intervenors, at least in part, and therefore, found that Bluegrass Water failed to establish the absence of wasteful duplication in this matter with respect to the Mission monitoring system. Thus, as shown in Appendix A, the Commission has included a reduction of $161,500 in the overall decrease in UPIS to eliminate the capital cost on the Mission control monitoring systems.[126]

Accumulated Depreciation. Bluegrass Water explains that accumulated depreciation consists of the historic total of plant depreciation to date.[127] Accumulated depreciation associated with assets acquired by Bluegrass Water from the prior owners have been carried forward on the books of Bluegrass Water.[128] Bluegrass Water's 13-month average for accumulated depreciation for its sewer system is calculated to be $2,564,880.[129]

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[124] *Id.* at 14-15.

[125] *Id.* at 15.

[126] *See* Appendix A.

[127] Application, Exhibit 8, Thies Testimony at 13.

[128] *Id.* at 13-14.

[129] *Id.* at 14.

The depreciation rates that Bluegrass Water proposes to use in this instant case are the same rates approved for affiliates to use in other jurisdictions and are not based on a depreciation study.[130] To evaluate the reasonableness of the depreciation practices of small water and sewer utilities, the Commission has historically relied upon the report published in 1979 by the National Association of Regulatory Utility Commissioners (NARUC) titled *Depreciation Practices for Small Water Utilities* (NARUC Study) and the *O&M Guide for the Support of Rural Water-Wastewater Systems* (O&M Guide). When no evidence exists to support a specific life that is inside or outside of the NARUC and O&M Guide ranges, the Commission has historically used the mid-point of the depreciation ranges to depreciate utility plant.[131]

Bluegrass Water has not presented any supporting analysis or study to show that its depreciation lives are appropriate. Further, because the Commission is adjusting UPIS to reflect plant constructed in 2019, 2020, and the forecasted test-year, accumulated depreciation is being set equal to the depreciation expense for the test year. Given that the Commission's forecasted UPIS is not broken down by account, the Commission is using a composite rate based on the NARUC and the Operation & Maintenance (O&M) Guide depreciation rates.

Applying the NARUC and O&M Guide composite sewer rate of 3.3 percent[132] results in a 13-month average accumulated depreciation balance of $56,749 which in a decrease to Bluegrass Water's accumulated depreciation of $2,508,131.

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[130] Responses to Staff's Second Request, Item 2.

[131] Case No. 2020-00195, *Electronic Application of Southeast Daviess County Water District for an Alternative Rate Adjustment* (Ky. PSC Dec. 30, 2020).

[132] Responses to Staff's Third Request, Item 7(b).

Cash Working Capital Allowance. Bluegrass Water calculated its cash working capital allowance of $256,178 by using the 45 day or 1/8th formula methodology, after adjusting for the impacts of Bluegrass Water's proposed adjustments to O&M expenses. While the Commission finds the 1/8th approach to be a reasonable approach for Bluegrass Water, particularly given its size and relative sophistication, and the Commission will permit its use in this matter given those factors, the Commission's cash working capital allowance of $186,692 reflects the pro forma O&M expense determined reasonable herein.

Contributions In Aid of Construction (CIAC). CIAC carried on the books of Bluegrass Water is from the books and records of the prior owners of the acquired system assets.[133] The forecasted test year reflects additional CIAC that resulted from the system acquisitions approved by the Commission in Case No. 2020-00028 and those acquisitions that will be consummated in Case No. 2020-00297.[134] The 13-month average balance of CIAC Bluegrass Water has included in rate base is $100,385.[135] Eliminating the CIAC recorded for Delaplain of $76,684 results in a CIAC of $23,701.

Based on the adjustments discussed above, the Commission has determined that Bluegrass Water's net investment rate base for its sewer division is $2,601,721.

[133] Application, Exhibit 8, Thies Direct Testimony at 15.

[134] *Id.*

[135] *Id.*

Rate Base Component - Sewer	Application 13-Month Average Rate Base	Commission Adjustments	Commission 13-Month Average Rate Base
Utility Plant In Service	$ 8,438,874	$ (6,719,196)	$ 1,719,678
Accumulated Depreciation	(2,564,880)	2,508,131	(56,749)
Net Utility Plant in Service	5,873,995	(4,211,066)	1,662,929
Construction Work In Progress	877,758	(116,034)	761,724
Working Capital Allowance	256,178	(55,409)	200,769
Contributions in Aid of Construction	(100,385)	76,684	(23,701)
Jurisdicitional Rate Base	$ 6,907,546	$ (4,305,825)	$ 2,601,721

Rate Base - Water

Bluegrass Water proposed a forecasted net investment rate base for its water division of $968,960 based on a 13-month average for that period.[136] In its Base Period Update, Bluegrass Water increased its proposed water rate base to $1,050,294.[137]

As discussed below in this Order, the Commission has determined that Bluegrass Water's net investment water rate base is $562,971.

Utility Plant In Service. Bluegrass Water reported a base year UPIS balance of $1,188,537.[138] According to Bluegrass Water, its base year UPIS balance reflected the

[136] Responses to Staff's First Request, Item 1, Excel Workbook: https: BGUOC2020RateCase-RateBase_%28Water%29.xlsx; Tab: FY Rate Base - Water B1.

[137] Base Period Update (filed Mar. 19, 2021), Excel Workbook: BYupdate-RateBase%28Water%29; Tab: FY Rate Base - Water B1.

[138] Responses to Staff's First Request, Item 1, Excel Workbook: https: BGUOC2020RateCase-RateBase_%28Water%29.xlsx; Tab: FY Rate Base - Water B1.

actual amounts recorded on its books as of August 31, 2020, and the forecasted UPIS additions for the four-month period ending December 31, 2020.[139] Bluegrass Water explained that its 13-month average UPIS of $1,188,537 was calculated by adding forecasted acquisitions and plant additions and subtracting forecasted retirements through April 2022.[140] However, as noted above with respect to sewer, Bluegrass Water did not actually project any retirements in the forecasted period. Thus, as above, the Commission calculated a 13-month average UPIS to include the construction completed in 2019, 2020, and the forecasted test-year construction using information provided by Bluegrass Water regarding the amounts and timing of proposed project additions provided in response to Staff's Second Request, Item 8. However, for the same reasons discussed above with respect to sewer, the Commission eliminated the proposed remote monitoring costs and the cost of a $15,000 construction item that Mr. Freeman testified had been eliminated just prior to the hearing. The 13-month average UPIS in the forecast period, as calculated by the Commission, with the monitoring costs and cancelled construction item eliminated, is $419,882 which is $768,655 below the forecasted UPIS included by Bluegrass Water in its application. The Commission's calculation of its 13-month average UPIS is included in Appendix A.

<u>Accumulated Depreciation</u>. Bluegrass Water's accumulated depreciation consists of the historic total of plant depreciation to date.[141] Accumulated depreciation associated with assets acquired by Bluegrass Water from the prior owner have been carried forward

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[139] Application, Exhibit 8, Thies Direct Testimony at 13.

[140] *Id.*

[141] Application, Exhibit 8, Thies Direct Testimony at 13.

on the books of Bluegrass Water.[142] Bluegrass Water's 13-month average for accumulated depreciation for its water system is calculated to be $263,430.[143]

The depreciation rates that Bluegrass Water proposes to use in this instant case are the same rates approved for affiliates to use in other jurisdictions and are not based on a depreciation study.[144] Bluegrass Water has not presented any supporting analysis or study to show that its depreciation lives are appropriate. Further, because the Commission is adjusting UPIS to reflect plant constructed in 2019, 2020, and the forecasted test-year, accumulated depreciation is being set equal to the depreciation expense for the test year. Given that the Commission's forecasted UPIS is not broken down by account it is using a composite rate based on the NARUC.

Applying the NARUC composite sewer rate of 2.82 percent[145] results in a 13-month average accumulated depreciation balance of $11,667 which in a decrease to Bluegrass Water's accumulated depreciation of $251,763.

<u>Construction Work In Progress (CWIP)</u>. Bluegrass Water defines CWIP as the value of utility plant that is under construction but has not yet been placed into service.[146] Bluegrass Water's forecasted CWIP of $97,909 is based on a 13-month average of the forecasted balances from April 1, 2021, through April 30, 2022.[147] Using the construction completed in 2019, 2020, and the forecasted test-year construction the Commission

[142] *Id.* at 13–14.

[143] *Id.* at 14.

[144] Responses to Staff's Second Request, Item 2.
[145] Responses to Staff's Third Request, Item 8.b.

[146] Application, Exhibit 8, Thies Direct Testimony at 13.

[147] *Id.*

calculated a 13-month average CWIP of $212,036 which is $114,127 greater than the amount Bluegrass Water's forecasted. The Commission's calculation of its 13-month average CWIP is included in Appendix A.

Cash Working Capital Allowance. Bluegrass Water calculated its cash working capital allowance of $35,266 by using the 45 day or 1/8th formula methodology, after adjusting for the impacts of Bluegrass Water's proposed adjustments to O&M expenses. While the Commission finds the 1/8th approach to be a reasonable approach for Bluegrass Water, particularly given its size and relative sophistication, and the Commission will permit its use in this matter given those factors, the Commission's cash working capital allowance of $32,042 reflects the pro forma O & M expense determined reasonable herein.

Based on the adjustments discussed above, the Commission has determined that Bluegrass Water's net investment rate base for its water division is $562,971.

	Application 13-Month Average Rate - Base	Commission Adjustments	Commission 13-Month Average Rate - Base
UPIS	$ 1,188,537	$ (768,655)	$ 419,882
Accumulated Depreciation	(263,430)	251,763	(11,667)
Net Utility Plant in Service	925,106	(516,891)	408,215
CWIP	97,909	114,127	212,036
Working Capital Allowance	35,266	(3,224)	32,042
CIAC	(89,322)		(89,322)
Jurisdicitional Rate Base	$ 968,960	$ (405,989)	$ 562,971

REVENUES AND EXPENSES

Bluegrass Water developed an operating statement for its forecasted test period based on its budgets for the 2020 fiscal year. As required by 807 KAR 5:001, Section 16(6)(a), the financial data for the forecasted test period was presented by Bluegrass Water in the form of pro forma adjustments to its base period, the 12 months ending December 31, 2020. Based on the assumptions built into its budgets, Bluegrass Water calculated its test year water revenues and O&M expenses to be $90,000 and $254,014, respectively, and its test year sewer revenues and O&M expenses to be $1,154,988 and $2,049,424, respectively. Based on these adjusted revenues and O&M expenses, Bluegrass Water's test period water and sewer operating income (loss) was ($196,047) and ($1,176,152).[148] Based on a proposed ROE of 11.80 percent, Bluegrass Water determined that it required a revenue increase of $336,747 for water and $2,177,052 for sewer.[149] The Commission will accept components of Bluegrass Water's test period revenue and expenses with certain adjustments discussed below.

Direct Expense Adjustments

1. Direct Administrative Expense

In the O&M expenses Bluegrass Water used to calculate its revenue requirement for both sewer and water, Bluegrass Water included a line item labeled "Administrative Services."[150] A breakout of that line item in the work papers for Schedule CE4, as filed

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[148] *See* Response to Staff's First Request, Item 1, BGUOC2020RateCase-RevenueRequirement_and_ConversionFactor_(Sewer).xlsx; BGUOC2020RateCase-RevenueRequirement_and_ConversionFactor_(Water).xlsx.

[149] *Id.*

[150] *See* Schedule C-1, Response to Staff's First Request, BGUOC2020RateCase-IncomeStatement_(Sewer).xlsx, BGUOC2020RateCase-IncomeStatement_(Water).xlsx.

with Bluegrass Water's application, indicates that expense consists of "Legal Fees," "Manage Consult," and "IT" expenses.[151] The bulk of the Administrative Services expense in the schedules filed with Bluegrass Water's application was attributable to "Manage Consult" expense ($39,088 and $3,066 for sewer and water, respectively, in the base period with $36,000 and $6,176 projected for the forecasted period).[152]

When asked to identify who provided the Manage Consult services, the scope of their services, and how those services differed from services provided by CSWR, Bluegrass Water identified PH Enterprises, LLC, Elasticity LLC, and James Fallert Consultant, LLC as providing the services included as Manage Consult expense. Bluegrass Water stated that PH Enterprises provided Utility Operations Consulting and argued that the contract services were needed because PH Enterprises facilitates tap fees for new service connections and CSWR employs no project management staff in Kentucky; that Elasticity provided Communications and Public Relations service and that the service was needed because CSWR employs no public relations professionals; and that James Fallert Consultant provided Legal and Regulatory Consulting and that the service was needed because Mr. Fallert has expertise and decades of experience in regulatory accounting and finance.[153]

In response to subsequent requests for information regarding the specific costs incurred for the direct services provided by PH Enterprises, Elasticity, and James Fallert,

[151] Response to Staff's First Request, Item 1 BGUOC2020RateCase-IncomeStatement_(Sewer).xlsx, BGUOC2020RateCase-Schedule_CE4.xlsx.

[152] *Id*. at Tab Base & Forecast Detail.

[153] Response to Staff's Third Request, Item 3.

Bluegrass Water indicated that PH Enterprises provided direct service for its sewer operations for $2,000 per month from January 2020 through September 2020 for a total of $18,000; that Elasticity provided direct service for Bluegrass Water from April 2020 through December 2020 at a total cost of $30,834, and that James Fallert provided direct service to Bluegrass Water's sewer operations in October 2020 totaling $12,600. In this updated information, Bluegrass Water also indicated that it paid Kentucky Rural Water Association $550 in December 2020, which Bluegrass Water included as Manage Consult expense.[154] Notably, the sum of what Bluegrass Water later reported as actual Manage Consult expenses in the base period was significantly higher than what Bluegrass Water initially included in Schedule CE4 for the base period.[155]

Joint Intervenors argued that the Commission should closely scrutinize Bluegrass Water's direct contractor expense.[156] Joint Intervenors specifically note that a significant portion of Bluegrass Water's outside expense arises from services provided by Elasticity, and argue that "[t]he majority of the work Elasticity appears to have done for Bluegrass appears to have been promotional in nature."[157] Thus, citing 807 KAR 5:016, Joint Intervenors argue that the expense for Elasticity should be excluded.

In response to Joint Intervenors, Bluegrass Water argued that its expense for Elasticity was reasonable for ratemaking purposes. Bluegrass Water argued that the services offered by Elasticity provide material benefit to its customers. Thus, Bluegrass

[154] Response to Staff's Fourth Request, Item 9(e), 4-PSC-09(e).xlsx.

[155] *See* Response to Staff's First Request, Item 1, BGUOC2020RateCase-Schedule_CE4.xlsx (showing a total Manage Consult Expense for water and sewer of $42,153);

[156] Joint Intervenors' Brief at 14–15.

[157] *Id.* at 15.

Water argues that those expenses are allowable pursuant to 807 KAR 5:016, Section 3(2).

With respect to expenses attributable PH Enterprises, it is not clear what services PH Enterprises was providing or whether the contract price was reasonable. Bluegrass Water was making payments to PH Enterprises, an apparent affiliate of a previous owner of the Longview/Homestead system, pursuant to the sales contract for the Longview/Homestead system.[158] Moreover, although the sales contract that established the relationship indicated payments would be made based upon work completed, PH Enterprises invoices are numbered "1 of 12" through "12 of 12" and are simply for $2,000 per month such that they do not appear to be tied to any particular work. Further, the expenses appear to have terminated upon payment of the twelfth of twelve invoices. Thus, the Commission finds that Bluegrass Water failed to establish that the direct expenses for PH Enterprises are reasonable expenses that should be recovered from customers in the forecasted test year (or that they will even be incurred in the forecasted test year).

With respect to the direct expenses for Elasticity, the Commission observes that the detail provided for the specific projects attributed to Bluegrass Water identified in invoices provided does not provide sufficient information to establish that they resulted in material benefit to Bluegrass Water's utility customers, and the specific projects appear to be one off occurrences e.g. handling the press related to acquisitions and the

[158] Response to Staff's Third Request, Item 3, KY2020-290_BW_0774- KY2020-290_BW_0788 (sale contract provided as contract for services).

production of a video to show some systems before and after construction.[159] Moreover, the work product provided in response to Joint Intervenors' Post-Hearing Request for Information, which consisted in large part of social media posts that were rarely specific to Bluegrass Water customers, would provide little, if any, benefit to Bluegrass Water's customers. There were a few correspondences from Bluegrass Water or CSWR to customers regarding specific issues related to Bluegrass Water's service that Bluegrass Water indicated Elasticity assisted in drafting, but that work appeared to be minimal and the cost of such correspondence were not broken down such that it was impossible to determine what small portion of the cost might be attributable to that work. Moreover, given the expense Bluegrass Water is already paying CSWR for general and administrative work and Bluegrass Water's size, the Commission questions the need for Bluegrass Water to retain an outside public relations firm at a direct cost of over $30,000 to assist with such matters. Thus, the Commission finds that Bluegrass Water failed to establish that the direct expenses for Elasticity provided material benefit to Bluegrass Water's customers and, therefore, that they are recoverable pursuant to 807 KAR 5:016.

With respect to the direct expenses for James Fallert, it is not clear what services he was providing. The contract Bluegrass Water provided for Mr. Fallert indicated that he was primarily providing services related a rate case,[160] but Mr. Fallert was not offered as a witness in this matter and Bluegrass Water indicated that rate case expense had not

[159] *See* Response to Staff's Third Request, Item 3, KY2020-290_BW_0803- KY2020-290_BW_0826.

[160] Response to Staff's Third Request, Item 3, KY2020-290_BW_0827.

been included.[161] Work papers provided by Bluegrass Water also indicate that the expense for Mr. Fallert's services accrued in a single month, October 2020, after Bluegrass Water tendered its application and testimony in this matter.[162] Moreover, CSWR employs a number of accounting professionals, both directly and as contractors, and a portion of their cost is allocated to Bluegrass Water in this matter.[163] Finally, even if the basis for the expense was reasonable and should have been allocated to Bluegrass Water's customers, it is not clear that the expense would reoccur during the forecasted test year given that it accrued in a single month. Thus, the Commission finds that Bluegrass Water failed to establish that the direct expense for James Fallert Consultant is a reasonable expenses that should be recovered from Bluegrass Water's customers in the forecasted test year.

Bluegrass Water projected $36,000 in Manage Consult expense for sewer and $6,176 in Manage Consult expense for water in the forecasted period. Bluegrass Water indicated that it projected those expenses based on the expenses incurred in the base period and discussed above.[164] Because the Commission finds that Bluegrass Water failed to establish that the direct expense for PH Enterprises, Elasticity, and James Fallert Consultant are reasonable expenses that should be recovered in the forecasted test year, the Commission must adjust the expenses for Manage Consult expenses in Bluegrass

[161] Response to Staff's Third Request, Item 24.

[162] Response to Staff's Fourth Request, Item 9(e), 4-PSC-09(e).xlsx.

[163] *See* Response to Staff's Second Request for Information, Item 1(c), 2-PSC-01c.xlsx (showing $133,000 in Auditor and Accounting Services in the allocated overhead); Response to Staff's Second Request for Information, Item 14 PSC 2-14 (showing a number of accounting professionals employed by CSWR).

[164] *See* Response to Staff's Third Request, Item 3(d).

Water's forecasted test year projections. Thus, the Commission will reduce Bluegrass Water's Manage Consult expense for sewer by $35,450, which reflects amounts paid to the Kentucky Rural Water Association as the only remaining expense, and will reduce its Manage Consult expense for water by $6,176 to reflect the elimination of any of the expenses discussed above from the projected revenue requirement.

2. Depreciation Expense

Bluegrass Water calculated depreciation expense for the sewer division of $264,095 by multiplying its proposed depreciation rates by the end of the forecasted period UPIS balances.[165] Even assuming its depreciation rates were supported by the record, Bluegrass Water acknowledged at the hearing that it would be incorrect to apply the rates to the ending balance UPIS in the forecasted period, but rather, acknowledged that the rates should be applied to the 13-month average UPIS balances. Thus, the Commission will adjust Bluegrass Water's depreciation expense to reflect the correct application of the rates to the 13-month average balance.

Bluegrass Water included a negative net salvage value in its depreciation rates, which had the effect of increasing the depreciation rate. However, Bluegrass Water acknowledged that it had not provided specific evidence to support the negative net salvage values.[166] Further, it acknowledged that two of its projects included decommissioning costs for existing plant.[167] The Commission finds that large projects to

[165] *See* Response to Staff's First Request, Item 1, BGUOC2020RateCase-RateBase_(Sewer).xlsx, Tab Dep - FY B3.1 (showing that depreciation expense for a particular account is calculated by multiplying the end of period UPIS by the depreciation rate)

[166] Response to Staff's Third Request, Item 5 and 6.

[167] Response to Staff's Third Request, Item 17.

replace significant plant assets likely also have decommissioning costs baked into the estimates (a utility must "replace" existing plant by removing what is currently there), so Bluegrass Water is seeking to have its customers pay for at least some decommissioning costs of existing plant while also recovering a separate negative net salvage value. Given that the negative net salvage value is not supported by evidence, there is no way to determine if its inclusion under the circumstances will result in duplicative cost recovery or if it is otherwise reasonable. Thus, the Commission finds that Bluegrass Water failed to establish that a negative net salvage value is appropriate in this case.

With respect to the depreciation rates used to calculate depreciation expenses, Bluegrass Water has not presented any supporting analysis or study to show that its proposed depreciation lives are appropriate. Rather, Bluegrass Water indicated that its proposed depreciation rates are based on the rates used by its systems in other jurisdictions.[168] However, Bluegrass Water further indicated that even those rates are not based on a depreciation study, and Bluegrass Water provided no other information to indicate that its proposed depreciation rates are reasonable.[169]

As noted above, when no evidence exists to support a specific life that is inside or outside of the NARUC and O&M Guide ranges, the Commission has historically used the mid-point of the depreciation ranges to depreciate utility plant as discussed above in the

[168] *See* Thies Testimony at 16 (indicating that the rates are based on rates used in other jurisdictions); *see also* Response to Staff's Second Request, Item 2 (indicating that the rates on which Bluegrass Water based its rates are not based on any depreciation study).

[169] *See also* Response to Staff's Second Request, Item 2 (indicating that the rates on which Bluegrass Water based its rates are not based on any depreciation study).

section discussing accumulated depreciation.[170] The Commission finds that it is appropriate to do so here. However, because Bluegrass Water's UPIS numbers were unreliable and the Commission had to establish a rate base based on projected construction, the UPIS found to be reasonable in this matter is not broken down by account. Thus, the Commission is applying a composite depreciation rate based on the NARUC and the O&M Guide to the 13-month average UPIS.[171]

Applying the NARUC and O&M Guide composite sewer rate of 3.3 percent and removing CIAC amortization of $7,052 results in a 13-month average depreciation expense of $49,697 which in a decrease to Bluegrass Water's forecasted depreciation expense of $214,398. For the water division total deprecation net of CIAC amortization is calculated to be $11,667 based on the NARUC midpoints, which represents a decrease of $20,274.

3. Operator Contractor Expense

In its application, Bluegrass Water included operating expenses attributed to system operator contracts of $1,029,348 and $144,048 for its sewer and water systems, respectively, in the forecast period. The majority of the costs are paid to Midwest.

Joint Intervenors have recommended that Bluegrass Water's system operator contract expense to be reduced to reflect two factors. First, they argue that Bluegrass Water has implemented and is seeking recover the cost for remote monitoring despite

[170] Case No. 2020-00195, *Electronic Application of Southeast Daviess County Water District for an Alternative Rate Adjustment* (Ky. PSC Dec. 30, 2020).

[171] The Commission observes that Bluegrass Water projected depreciation expense for amounts it had not placed in place accounts based on composite rate as well and that such a practice is not uncommon.

paying higher costs to its operator contractor to inspect each system daily. As noted above, Joint Intervenors argue this represents an unnecessary duplication of costs. Second, Joint Intervenors argue that Bluegrass Water confirmed at the hearing that the average cost of the operator agreements is likely to fall at the end of the test year as contracts expire and are renegotiated at a lower rate. Thus, Joint Intervenors propose adjusting all existing contract costs to reflect the cost of the most recently negotiated agreement.

Bluegrass Water responded that because it is required to have operators on site at the systems each day, even with a remote monitoring system in place, it still must comply with this legal requirement and, therefore, the associated expenses should not be disallowed.

The Commission agreed with Joint Intervenors that paying contractors to inspect each system daily as required by the regulation while paying for remote monitoring costs raised questions about duplicative costs. This is why the Commission found that Bluegrass Water failed to prove the absence of wasteful duplication with respect to the remote monitoring equipment and excluded the costs of remote monitoring as discussed above. However, the removal of those costs removes the duplicative costs associated with both monitoring and daily inspections. Thus, the duplicative costs alleged by Joint Intervenors do not justify *also* adjusting Bluegrass Water's operator expense.

Further, the evidence indicates that Bluegrass Water did competitively bid the operator contracts and selected the lowest cost option. The Commission agrees with Joint Intervenors that that the operator contractor costs are likely to fall in the future, as Bluegrass Water indicated that it anticipated. However, the contracts at issue have 2-

year terms such that the first of the four contract terms will not expire until about September 2021. Bluegrass Water could arguable rebid that contract leading up to the end of the term, and there could be savings that the Commission could reflect in this matter, but as with the more recent contracts, Midwest Operators, which won the bids on the earlier contracts, would be the only operator that could take advantage of economies of scale and potentially bid a lower cost.

Greater savings should be achieved in the future by bidding out the operator contracts for all systems together or in groups based on geography as Bluegrass Water indicated it planned to do. If Bluegrass Water rebids its current contracts, which it entered as it purchased systems, based on when the terms expire as opposed to waiting and bidding them in larger groups based on geography, then Midwest Operators will always have an advantage in bidding contracts such that it will not need to lower costs to win the bid. Further, if the Commission forced Bluegrass Water to recognize the savings Midwest Operators are likely to offer if a full open bid took place as each contract expired, then Bluegrass Water would likely be forced to rebid the contracts as they expired to recognize that savings and would thereby be unable to bid all systems at the same the time or based on geography when a number of the contracts have expired. Thus, the Commission finds that an adjustment to operator contract expense would not be appropriate here.

However, the Commission notes that it is making this decision with the understanding that Bluegrass Water will requests bids and proposals from numerous operators for the majority of its systems and for its systems based on geography to allow more operator contractors to take advantage of the economies of scale or regional benefits when bidding the contracts. The Commission expects that greater savings will be seen in future rate cases.

Allocated Expense Adjustments

1. Allocation Methodology

Most general and administrative work is performed for Bluegrass Water through its parent company, CSWR, which is managed by an affiliate, Central States. However, CSWR, through Central States, performs general and administrative work for all utilities owned and operated by CSWR and engages in business development activities to acquire additional utilities across the country. Bluegrass Water has no formal cost allocation manual to allocate costs internally between the various affiliates of CSWR and business development activities performed by CSWR.[172]

Bluegrass Water determined the amount of allocated expense for this rate case by first projecting CSWR's "Total SG&A Budget,"[173] which is all of CSWR's budget excluding costs that are allocated directly to a utility affiliate.[174] Bluegrass Water indicated that it then identified and eliminated CSWR's expenses related to business development, referred to as BD Expense in various workpapers,[175] because Bluegrass Water stated "those expenses would provide only marginal benefit to Bluegrass Water."[176] Bluegrass

[172] Response to Attorney General's First Request, Item 48.

[173] *See* Schedule OHA1.

[174] Response to Staff's First Request, Item 1(a).

[175] *See* Schedule OHA1 (showing the elimination of "BD expenses" from the SG&A Budget before Bluegrass Water applied the Massachusetts' method).

[176] Response to Staff's Second Request, Item 1(b) (explaining what "BD expense" is and why Bluegrass Water was seeking to eliminate it).

Water then applied what it referred to as the Massachusetts' method or formula to allocate the remaining expenses between the utility affiliates owned by CSWR or projected to be owned by CSWR in the fourth quarter of 2021.[177]

Bluegrass Water was asked to explain how it determined the BD Expense it excluded from the SG&A Budget, and it indicated that it excluded all of the compensation expense of employees designated specifically as business development employees, because they worked solely on business development activities.[178] Bluegrass Water explained that it then removed a portion of the total compensation expense for three officers, because the officers were involved in supervising the business development employees. Lastly, Bluegrass Water removed a portion of the amounts budgeted as office supply and travel expense in the SG&A budget.[179]

At the hearing, Bluegrass Water was questioned regarding other employees work on business development activities, and it acknowledged that other employees worked on new acquisitions.[180] Bluegrass Water was also questioned regarding why portions of other expense items shown in the SG&A Budget, such as rent, insurance, management consulting, IT consulting, and auditing and accounting consulting, were not allocated to business development. Bluegrass Water was asked to identify portions of other expense items in the SG&A Budget that should have been allocated to business development

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[177] Thies Testimony at 10-11; *see also* Schedule OHA1.

[178] Response to Staff's Third Request, Item 22.

[179] *Id.*

[180] *See* May 19, 2021 H.V.T. at 16:15:14-16:16:53; *see also* May 19, 2021 H.V.T. at 09:14:56-09:22:54.

expense as a post-hearing request for information, but it claimed the only business development expense that was not already allocated was the workers compensation expense for the business development employees.[181]

With respect to the allocation of SG&A Budget after BD Expense is eliminated, Bluegrass Water explained that the Massachusetts formula is based on the ratio of direct labor, capital investment and gross revenue of each affiliate to total direct labor, capital investment and gross revenue.[182] Bluegrass Water asserts that the component factors used in the formula correspond to the significant drivers of general and administrative expense at CSWR.[183] Bluegrass Water asserted, for example, that a higher level of capital investment would require more time and higher expense to perform the necessary accounting procedures to track those fixed assets.[184] For the forecasted test year, as calculated in the application, the Massachusetts' formula produced an allocation percent factor for Bluegrass Water of 5.25 percent, which Bluegrass Water applied to the Total

[181] Response to Joint Intervenors' Post-Hearing Request, Item 10; *see also* May 19, 2021 H.V.T.

[182] Thies Testimony at 11.
[183] *Id.*

[184] *Id.*

SG&A Budget for the forecasted period,[185] less the amounts Bluegrass Water allocated to business development expense, to determine the amount of allocated overhead that should be assigned to Bluegrass Water.[186]

The Joint Intervenors argue that Bluegrass Water failed to include all business development expenses in determining the amount to be excluded from the SG&A budget before applying the Massachusetts formula. Joint Intervenors assert that Bluegrass Water conceded that it had not taken into account information technology infrastructure, office rents, insurance, legal, and payroll taxes when identifying business development expenses that should be excluded. Joint Intervenors argue that these and any other expenses not related to providing service to Bluegrass Water's customers should be excluded.[187]

Joint Intervenors also argue that the use of the Massachusetts formula to allocate the remaining overhead in this case may not be appropriate based on several factors.

[185] The Commission notes that in Schedule OHA1, as filed with the application, Bluegrass Water indicated that the total SG&A budget for the forecasted test year was $11,173,000 and allocated $4,771,832 of that to BD Expense for a net SG&A budget to be allocated to utility affiliates of $6,401,169. When Bluegrass Water was asked for a breakdown of the SG&A Budget for the forecasted test year, Bluegrass Water provided an itemized SG&A Budget that totaled only $7,976,342. *See* Response to Staff's Second Request, Item 1(c), 2-PSC-01c.xlsx. When Bluegrass Water was asked to identify those portions of $7,976,342 it would consider to be BD Expense under its methodology, Bluegrass Water identified $1,194,774 in BD Expense such that the net SG&A budget to be allocated to utility affiliates became $6,781,568. *See* Response to Staff's Fourth Request, Item 5, 4-PSC-05.xlsx; *see also* Response to Staff's Third Request, Item 23 (where Bluegrass Water was unable to provide a breakdown of BD Expense in the forecasted period). Bluegrass Water later explained this discrepancy by stating that the Total SG&A Budget and BD Expense in Schedule OHA1 were projected numbers for 2022, not the forecasted period as indicated, that Bluegrass Water did not project the 2022 budget in sufficient detail to provide any kind of breakdown, and that the itemized SG&A Budget ultimately provided was based on 2021 projections. The Commission will use the projected 2021 SG&A budget when referring to the SG&A budget in the forecasted period going forward, since there is no way to know what is in the 2022 budget, but notes that the discrepancy does raise questions about the accuracy of Bluegrass Water's projections of the SG&A budget, especially given the significant differences.

[186] *See* Schedule OHA1.

[187] Post-Hearing Brief of the Joint Intervenors at 12.

Joint Intervenors state that Bluegrass Water's Utility Plant in Service balance is low as a percentage of the total system, because this proceeding is the first general rate adjustment sought by Bluegrass Water.[188] Conversely, Joint Intervenors note that Bluegrass Water produces a significantly higher amount of revenue when compared to other companies within CSWR, which Joint Intervenors assert suggests that Bluegrass Water's revenues are proportionately high compared to utility plant of other CSWR companies.[189] Finally, Joint Intervenors reference what they call a redundancy inherent in contracting costs, discussed above in this order, and state that it is not clear if Bluegrass Water's direct labor expenses reflect the true cost of corporate labor to CSWR.[190] Given these factors, Joint Intervenors propose that a better allocation method is one based on Bluegrass Water's total customer connections as a percent of the total connections within CSWR, which results in an allocation percentage of 4.0 percent.[191]

Bluegrass Water asserts that it has allocated common costs appropriately for ratemaking purposes. Bluegrass Water refutes Joint Intervenors' position, stating that the Massachusetts formula remains the most appropriate allocation methodology that allows for a consistent analysis. Bluegrass Water states that using the Massachusetts formula is better than some "arbitrary and unclear 'test' with no basis in the data provided."[192]

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[188] Bluegrass Water's Correction to Test Year Update at 19.

[189] *Id.*

[190] Post-Hearing Brief of the Joint Intervenors at 13.
[191] *Id.* at 14.

[192] Post-Hearing Brief of Bluegrass Water at 10.

Pursuant to KRS 278.2207, "services and products provided to the utility by an affiliate shall be priced at the affiliate's fully distributed cost but in no event greater than market or in compliance with the utility's existing USDA, SEC, or FERC approved cost allocation methodology." Further, "[i]n any formal commission proceeding in which cost allocation is at issue, a utility shall provide sufficient information to document that its cost allocation procedures and affiliate transaction pricing are consistent with the provisions of this chapter."[193] If a utility has failed to provide sufficient evidence of its compliance, the Commission may "[o]rder that the costs attached to any transaction be disallowed from rates."[194]

With respect to the allocation of the SG&A Budget between CSWR's utility affiliates after BD Expense is removed, the Commission agrees with Joint Intervenors that use of the Massachusetts formula is not reasonable under the circumstances. Specifically, due to the nature of CSWR's business model, CSWR is in the process of purchasing new systems that often have rates that are artificially low and plant that has seen little investment in years. Conversely, Bluegrass Water is proposing significant investment through the forecasted period as well as a rate increase such that Bluegrass Water's revenue and UPIS could be higher than a comparatively larger CSWR utility simply based on the timing of proposed investment or the rate increase. Additionally, as discussed in more detail above, Bluegrass Water's UPIS numbers provided in its application are not credible given that Bluegrass Water failed to include retirements in the base and forecasted period, among other things, and Bluegrass Water acknowledged errors in

[193] KRS 278.2209.

[194] KRS 278.2211(1)(b).

some of the numbers included in its Schedule OHA1, as filed with its application. Thus, while the Massachusetts formula may be appropriate under certain circumstances, perhaps even for Bluegrass Water if CSWR's utility affiliates reach similar or stable places in terms of rates and investment, the Commission finds that Bluegrass Water failed to establish that the Massachusetts formula results in the proper allocation of costs in this matter.

Further, as proposed by Joint Intervenors, the Commission observes that it has often used customer equivalences to allocate general and administrative expenses when a cost of service study (COSS) is not available, as here, and there is not the means to allocate an expense directly. The Commission finds that this method is reasonable under the circumstances given the issues discussed above, and because customer equivalences do provide an estimate of the amount that would be spent providing general and administrative services. In fact, the Commission observes that Bluegrass Water proposed to allocate its portion of the expenses from CSWR between its sewer and water customers using a similar method.[195] Thus, the Commission generally finds Joint Intervenors proposal to use customer equivalents to allocate the SG&A Budget is reasonable.

However, while the Commission is in partial agreement with the Joint Intervenors, it takes issue with the fact that Joint Intervenors allocation based on customer equivalents is based on totals at the end of forecast period. The Commission notes that CSWR's total customer equivalences, what CSWR referred to as connections, changed significantly

[195] *See* Schedule OHA1.

during the forecasted period. Bluegrass Water's testimony indicated that at the end of April 2021 CSWR would have approximately 52,605 connections, that it would add approximately 7,000 connections by the end of June 2021, that it would add an approximately 10,200 connections by the third or fourth quarter of 2021, and that it would have approximately 85,000 total connections by the end of December 2021.[196] Based on that evidence, the Commission finds that CSWR will have 52,605 connections at the end of April 2021 and May 2021, 59,605 connections at the end of June 2021, July 2021, and August 2021, 69,805 connections at the end of September 2021, October 2021, and November 2021, and 85,000 connections at the end of each of the remaining months of the forecast period. The Commission finds that a 13-month average, using residential equivalents based on those findings, is a more appropriate method for allocating overhead than the methods proposed by Joint Intervenors or Bluegrass Water. That method yields a sharing percentage of 4.98 percent as shown in Appendix C.[197]

The Commission further finds, as proposed by Bluegrass Water, that expenses arising from business development activities should not be recoverable from utility customers and, therefore, that such expenses should be excluded from the SG&A Budget before it is allocated to utility customers using the sharing methodology identified above. However, the Commission finds that Bluegrass Water failed to establish that its method of identifying and excluding BD Expense is reasonable and results in Bluegrass Water customers paying only the fully allocated cost they should.

[196] May 19, 2021 H.V.T at 09:12:40; Response to Staff's Fourth Request, Item 12.
[197] Appendix C.

Bluegrass Water itemized the SG&A budget for the forecast period as follows:[198]

Admin & Human Resources	$	6,320,269
Office Supplies and Travel Expense		682,439
Management Consulting		243,300
Engineering Consulting		20,400
Auditor & Accounting Services		133,000
Legal Fees		87,684
IT		238,250
Rent		168,000
Insurance		77,000
Miscellaneous		6,000
Total Corporate SG&A	$	7,976,342

Bluegrass Water allocated $1,097,121 in Admin & Human Resources expense, which Bluegrass Water attributed to the compensation for the business development employees and a portion of the compensation for officers mentioned above, and $97,653 in Officer Supplies and Travel Expense to BD Expense.[199] Bluegrass Water later indicated that a very small portion of the Insurance expense in the SG&A budget, attributable to the workers compensation of the business development employees, should have been allocated to BD Expense. However, Bluegrass Water indicated that no other portion of the SG&A Budget should be allocated to BD Expense.[200]

The biggest issue with Bluegrass Water's assertion that no other portion of the SG&A Budget should be allocated to BD Expense is that its witnesses acknowledged that other employees worked on business development activities such a portion of those

[198] *See* Response to Staff's Second Request, Item 1(c), 2-PSC-01c.xlsx.

[199] *See* Response to Staff's Fourth Request, Item 5, 4-PSC-05.xlsx; *see also* Response to Staff's Third Request, Item 23 (where Bluegrass Water was unable to provide a breakdown of BD Expense in the forecasted period).

[200] Response to Joint Intervenor's Post-Hearing Request, 10.

employees work should be excluded.[201] Bluegrass Water also claimed after the hearing that IT expenses for business development activities, presumably only for the employees whose compensation was excluded, were excluded as part of exclusion of travel expense and office supplies, despite not previously indicating that before when asked how BD Expenses was allocated.[202] Bluegrass Water also claimed that no employee classified "exclusively" as a business development employee has a permanent office in CSWR's building but ignores the officers for which Bluegrass Water excluded a portion of those employees' compensation as part of business development expense as well as other employees it acknowledged were performing business development activities.

The Commission also observes that CSWR's business development activities are extensive. As noted above, Bluegrass Water indicated that it had about 52,606 connections as of April 2021 and that it is expected to have 85,000 connections by December 2021. Bluegrass Water has also made additional connections between January 2021 and April 2021, and it indicated that it expected to have about 120,000 connections by end of 2022. Thus, Bluegrass Water was or will be working on about 35,000 new connections at any given time in 2021 and 2022.

If the approximately 35,000 connections Bluegrass Water was or is seeking to acquire at any given time during the forecasted period were part of CSWR, they would represent between about 39.95[203] percent and 29.17[204] percent of CSWR's total

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[201] *See* May 19, 2021 H.V.T. at 16:15:14-16:16:53; *see also* May 19, 2021 H.V.T. at 09:14:56-09:22:54.

[202] *See* Response to Staff's Third Request, Item 22.
[203] 35,000/87,605=39.95%

[204] 35,000/120,000=29.17%

connections, based on the numbers used above. Given the process Bluegrass Water described for purchasing systems, and as acknowledged by Bluegrass Water's witnesses, it is clear that personnel other than those explicitly identified by Bluegrass Water are involved in such acquisitions. Moreover, those employees, in turn, use or benefit from resources, such as the building, office supplies, insurance, and legal and consulting services such that portions of those expense items should be allocated to business expenses. Thus, the Commission finds that Bluegrass Water failed to establish that its method of identifying and excluding BD Expense is reasonable and results in Bluegrass Water customers paying only the fully allocated cost they should.

Given that Bluegrass Water has the burden in this matter and on this issue in particular, the Commission could, in its discretion, disallow recovery of the allocated overhead.[205] In lieu of such a result, which likely would not be in the long term interest of Bluegrass Water or its customers, the Commission will treat Bluegrass Water's business development activities as if they are a separate utility with 35,000 connections throughout the forecasted test period and allocate the budget items of the SG&A Budget for the forecasted test year to BD Expense in the same way amounts are allocated above between CSWR utilities. Using that method will result in a sharing percentage of 33.61 percent, which the Commission will apply to the SG&A, except as discussed below, before allocating the remaining SG&A Budget among the utilities as discussed above.

[205] *See, e.g.* Case No. 2020-00342, *Electronic Application of CitiPower, LLC for a Rate Adjustment for Small Utilities Pursuant to 807 KAR 5:076*, (Ky. PSC Apr. 27, 2021), Order, at 5-7 (prohibiting recovery in rates of management fee paid to parent company for alleged general and administrative services due to utilities failure to provide proof that the fee is reasonable).

The effect of this change will be discussed below in the summary of the allocated overhead adjustments.

The Commission finds that this method of allocating BD Expense is reasonable, because it is consistent with how the Commission has allocated costs among utility operations in the past when no COSS has been completed and because it is clear from the evidence that Bluegrass Water's business development activities take up significant resources. The Commission also observes that this allocation method results in the Total SG&A Budget being allocated to BD Expenses at a rate roughly between the overall rate Bluegrass Water projected BD Expense would be allocated in the base period, 18 percent,[206] and the calendar year 2022, 42.71 percent.[207]

2. <u>Adjustments to SG&A Budget</u>

a. Admin & Human Resources

In its SG&A Budget for the forecast period, Bluegrass Water included $6,320,269 for the line item "Admin & Human Resources" in CSWR's SG&A budget.[208] In response to request for information, Bluegrass Water indicated that the only component of this line item is projected employee compensation for CSWR in the forecast period.[209] However, Bluegrass Water also provided a breakdown of employee compensation projected in the forecasted period which indicated the total employee compensation expense would be

[206] $1,181,221/$6,580,338=18%. *See* Schedule OHA1.

[207] $4,771,832/$11,173,000= 42.71 percent. *See* Schedule OHA1; *see also* Response to Staff's Third Request, Item 23 (indicating those numbers are calendar year 2022 projections).

[208] Response to Staff's Request, Item 1c, Schedule 2-PSC-01c.

[209] Response to Staff's Third Request, Item 11(b).

$6,083,987.[210] Bluegrass Water did not explain what additional expense, if any, accounted for that difference. Thus, the Commission finds that Bluegrass Water failed to establish that its customers should be responsible for any portion of that difference, and therefore, the Commission reduces the Admin & Human Resources expense in the SG&A Budget from $6,320,268 to $6,083,987.

b. New Employee Positions

In response to Staff's First Request, Item 18, Bluegrass Water provided all employee compensation for the forecasted test year broken down by categories of employees. The sum of the total employee compensation for the forecasted period provided in response to that request was $5,212,209.[211] Staff's Second Request asked Bluegrass Water to identify the employees included in the categories of employees that made up the total compensation for the forecasted period provided in response to Staff's First Request, Item 18. In response, Bluegrass Water provided the spreadsheet referenced above indicating CSWR's total employee compensation projected for the forecasted test year of $6,083,987.

When asked about the discrepancy in the amounts, Bluegrass Water stated that it was due to the inclusion of eight additional positions in the attachment provided in response to Staff's Second Request that were not in the response provided to Staff's First Request. It indicated two of the positions were labeled as 'Paralegal' and 'O&M IT Specialist' in response to Staff's Second Request and had since been filled. However, it noted that the employees for the other 6 positions were listed only as "New Position,"

[210] Response to Staff's Second Request, Item 14, PSC 2-14.xlsx.
[211] *See* Response to Staff's First Request, Item 18, KY2020-00290_BW_0078.

because they had not been filled. Bluegrass Water indicated that the positions were not included in response to Staff's First Request, because at the time it responded to that request, on January 29, 2021, it did not know the category into which the employees should be placed. Bluegrass Water stated that the six positions in which the person was identified as "New Position" were simply budgeted positions.[212]

The Commission finds that Bluegrass Water's inclusion of the six "New Position[s]" in the forecasted period is unreasonable because Bluegrass Water failed to establish that the cost would be incurred or that they should be allocated to Bluegrass Water's customers. The Commission observes that six new positions would represent over 13 percent of CSWR's projected employees and officers in the forecasted test year. Yet, at the end of January, when it responded to Staff's First Request, Bluegrass Water could not even place the projected employees in categories as broad as Exempt, Non-Exempt, Director, or Manager, which raises questions regarding why Bluegrass Water was projecting the new employees in the first place. Further, there was no evidence that the employees have been retained. Thus, the Commission finds that Bluegrass Water has not met its burden in establishing that the cost of those employees is an allocated cost for which Bluegrass Water's customers should be responsible and, therefore, further finds that CSWR's Admin & Human Resources expense in the forecasted test period should be further reduced by $691,141, from $6,083,987 to $5,392,846.

c. Health and Dental Insurance

[212] Response to Staff's Third Request, Item 11.

For both Health and Dental insurance benefits provided to employees, CSWR pays 99 percent of premiums, and the employees pay the remaining 1 percent.[213] In the forecasted test year, for employees not designated as new positions, CSWR included Health and Dental employer contribution totals of $696,691 and $35,881, respectively.[214]

The Joint Intervenors proposed a reduction in health and life insurance, citing Commission precedent in the treatment of employee insurance benefit costs.[215] Bluegrass Water objects to the position taken by the Joint Intervenors, stating that each CSWR employee does pay, in part, for the insurance and citing a failure of the Joint Intervenors to reference any applicable decision or guidance.[216]

The Commission has placed greater emphasis on evaluating employee total compensation packages for market and geographic competitiveness to ensure fair rate development and has generally determined that 100 percent employer-funded health and dental care does not meet that criteria.[217] In every general rate case filed since 2016 in which a utility sought to recover its expenses for the payment of 100 percent of its employees' health insurance premiums, the Commission has reduced test year expenses for health insurance premiums to levels based on national average employee contribution

[213] Response to Staff's First Request, Item 19.

[214] Response to Staff's Second Request, Item 14, Schedule 2-PSC-14 (Confidential).xlsx.

[215] Post-Hearing Brief of the Joint Intervenors at 12.

[216] Post-Hearing Brief of Bluegrass Water at 10.

[217] *See, e.g.,* Case No. 2016-00434, *Application of Shelby Energy Cooperative, Inc. for an Increase in its Retail Rates*, (Ky. PSC July 1, 2017) final Order at 6-7; Case No. 2016-00367, *Application of Nolin Rural Electric Cooperative Corporation for a General Rate Increase*, (Ky. PSC June 21, 2017) final Order at 10-11; Case No. 2016-00365, *Application of Farmers Rural Electric Cooperative Corporation for an Increase in Retail Rates*, (Ky. PSC May 12, 2017) final Order at 6-7; Case No 2016-00174, *Electronic Application of Licking Valley Electric Cooperative Corporation for a General Rate Increase*, (Ky. PSC Mar. 1, 2017) final Order at 18; Case No. 2017-00349, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates and Tariff Modifications*, (Ky. PSC May 3, 2018) final Order at 19.

rates. The Commission does not see any material difference between a utility paying 99 percent of the premiums and 100 percent of the premiums.

Bluegrass Water was questioned about the Commission's practice of reducing employer contributions for health and dental insurance premiums based on national average contributions. In response, Bluegrass Water argued that as a small company CSWR sees the need to offer best in class compensation and benefits in order to attract the most-qualified employees. Bluegrass Water further argued that "CSWR seeks to attract the most qualified individuals and views total compensation, including the benefits package, as key to achieving that goal."[218]

However, Bluegrass Water acknowledged that CSWR did not look at the typical private sector employer insurance contributions when it was determining what level of contributions for insurance it should provide.[219] Similarly, Bluegrass Water indicated that CSWR, through an outside consultant or otherwise, has not performed a study to compare its wages, salaries, benefits, and other compensation to other similarly-situated companies. Therefore, Bluegrass Water has not substantiated that it took any efforts to plan its compensation "to attract the most qualified individuals." Thus, Bluegrass Water has no evidence to support a finding that its contributions are reasonable and that Bluegrass Water's customers should be responsible for that level of contribution.

It is Commission practice that, in the absence of any compensation policy or benefits study regarding insurance benefits, an adjustment should be made to both health and dental insurance to bring the employee contributions in line with the Bureau of Labor

[218] Response to Staff's Second Request, Item 24.

[219] *Id.*

Statistics average employer contribution percentages of 21 percent[220] for health and the Willis Benefits Benchmarking Survey 60 percent[221] average contribution for dental insurance. Accordingly, the Commission has reduced CSWR's forecast period employer contributions for Health and Dental insurance by $139,338 and $21,248, respectively.[222] Thus, the Admin & Human Resources expense in the SG&A Budget should be further reduced by $160,586 from $5,392,846 to $5,232,260.

d. Increases to Employee Salary

In the forecasted test year, CSWR included $4,282,377 of salary compensation for employees.[223] At the end of the base year, however, total salary for all positions currently filled at CSWR totaled $3,918,741.[224] This increase was driven in large part by significant raises projected for several employees, including CSWR's President, who was projected to receive a salary of $350,228 in the base period and a salary of $450,000 in the forecasted test year. Such significant raises are unreasonable on their face, especially

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[220] Bureau of Labor Statistics, Healthcare Benefits, March 2019, Table 10, private industry workers. (https://www.bls.gov/ncs/ebs/benefits/2019/ownership/private/table10a.pdf); *see also* Bureau of Labor Statistics, Healthcare Benefits, March 2018, Table 10, private industry workers. (https://www.bls.gov/ncs/ebs/benefits/2018/ownership/private/table10a.pdf) (showing the same percentage contribution rate in 2018).

[221] *See* Case No. 2019-00109, *Electronic Application of Citipower, LLC (1) for Adjustment of Rates Pursuant to 807 KAR 5:076; (2) Approval for a Certificate of Public Convenience and Necessity to Purchase Pipeline and Other Related Assets; and (3) Approval of Financing*, Order (Ky. PSC Mar. 25, 2020) (citing the The Willis Benchmarking Survey, 2015, at 62-63 https://www.willis.com/Documents/publications/Services/Employee_Benefits/20151230_2015WillisBenefitsBenchmarkingSurveyReport.pdf); *see also* Case No. 2018-00129, Application of Inter-County Energy Cooperative Corporation for a General Adjustment of Existing Rates (Ky. PSC Jan. 25, 2019), Order.

[222] Appendix D.

[223] Bluegrass Water's Response to Staff's Second Data Request, Item 14, Schedule 2-PSC-14 (Confidential).

[224] Bluegrass Water's Response to Staff's Fourth Data Request, Item 6, Schedule PSC 4-6 CONFIDENTIAL.

for a company the size of CSWR. More importantly, Bluegrass Water provided no support for the reasonableness of projecting such raises or why such costs would be necessary. As noted above, Bluegrass Water has not performed any compensation study or analysis to determine the reasonableness of compensation proposed. Bluegrass Water has stated that it does not have a formal compensation policy or criteria, stating that the CSWR leadership "stays attuned to market conditions regarding employment and compensation levels".[225]

The Commission finds that Bluegrass Water has not met its burden of proof concerning the raises in salary from the end of the base period to the forecast period. In the absence of a supported compensation policy, the Commission finds it is appropriate to adjust salaries in line with the Bureau of Labor Statistics average of a 3.0 percent yearly increase.[226] Applying this to the end of base period rates produces a forecast period salary total of $4,105,088. Accordingly, the Commission has reduced CSWR's forecast period Admin & Human Resources by an additional $177,289[227] from $5,232,260 to $5,054,970

e. Auto Allowance

CSWR compensation for its executives includes a yearly auto allowance for certain employees totaling $102,000 in the forecast period.[228] Bluegrass Water justified the auto

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[225] Response to Staff's Second Request, Item 23(a); *see also* Response to Staff's Second Request, Item 11 (discussion how CSWR decided to provide specific executive salary increases).

[226] Bureau of Labor Statistics - EMPLOYMENT COST INDEX – March 2021 https://www.bls.gov/news.release/eci.nr0.htm

[227] Appendix D.

allowance based on extensive travel by the relevant employees.[229] However, a breakdown of CSWR's expense for employee travel to Kentucky indicates the inclusion of mileage payments for employees that received an auto-allowance,[230] which the Commission finds to be duplicative of direct payments made through the auto-allowance such that the auto-allowance payments are unreasonable. Thus, the Commission finds that CSWR's forecast period Admin & Human Resources expense should be reduced by an additional $102,000 from $5,054,970 to $4,952,970.

f. 401(k) Matching

As part of its benefits compensation, CSWR offers a 401(k) retirement plan, with an employer contribution of 3.0 percent of an employee's yearly salary,[231] with an additional 2.0 percent matching of additional employee contributions.[232] The Joint Intervenors state that as CSWR provides bonuses and discretionary 401(k) contributions without a formal criteria or written compensation policy, the total amounts tied to incentive compensation structures should be disallowed.[233] Bluegrass Water refutes the Joint Intervenors assertion that the 401(k) contributions are discretionary, stating that the

[228] Bluegrass Water's Response to Staff's Second Data Request, Item 14, Schedule 2-PSC-14 (Confidential).

[229] Response to AG's Second Request, Item 10.

[230] *See* Response to Staff's Fourth Request, Item 7, 04-PSC-07.xlsx.

[231] Bluegrass Water's Response to Staff's Third Data Request, Items 18-19.

[232] May 19, 2021 H.V.T. at 11:24:35, Cox Testimony.

[233] Post-Hearing Brief of the Joint Intervenors at 13.

additional contributions in excess of the base 3 percent are matching and depend on how much an employee chooses to invest.[234]

Concerning the 401(k) contributions, the Commission is in agreement with Bluegrass Water. As there is no discretionary portion of employer 401(k) contributions tied to financial performance, but represents a matching of employee contributions, no adjustment to reduce 401(k) contributions is necessary. However, the effect of adjustments to salaries discussed above will impact the allowable portion of 401(k) contribution in the forecast period. Accordingly, the Commission has reduced CSWR's forecast period Admin & Human Resources by an addition $8,864 from $4,952,971 to $4,944,106.[235]

g. Travel Expense

CSWR included a total overhead Travel Expense of $576,168 in the forecasted period.[236] As noted above, Bluegrass Water then eliminated a portion of that travel expense as business development expense and allocated a portion of the travel expense to Bluegrass Water based on a sharing percentage. Bluegrass Water did not provide any breakdown of CSWR's total travel expense in historical periods, beyond identifying employees that incurred portions of them, and the total travel expense Bluegrass Water identified for CSWR in historical periods—$109,830.90, $314,563.19, and $271,834.80 in 2018, 2019, and 2020, respectively—were significantly lower than the amount

[234] Post-Hearing Brief of Bluegrass Water at 10.
[235] Appendix D

[236] Bluegrass Water's Response to Staff's Third Request for Information, Item 12a.

projected in the forecasted test year.[237] Thus, the Commission is not able to find that Bluegrass Water's total projected travel expense in the forecasted test period is reasonable or that the costs should be recovered from Bluegrass Water's customers.

More importantly, Bluegrass Water did provide the actual costs for travel to Kentucky in 2019, 2020, and part of 2021. The records provided show that Bluegrass Water incurred $26,199 in expense for travel to Kentucky in 2019, $7,487 in expense for travel to Kentucky in 2020, and $3,797 in expense for travel to Kentucky in 2021 through at least April 2021 (the records were provided in May 2021 and included costs dated May 2021 such that they must have included part of the cost through May). If the travel expense for employees Bluegrass Water identified as business development employees in each of those years is eliminated, then the records provided by Bluegrass Water show expense for travel to Kentucky in the amount of $12,714 in 2019, $4,820 in 2020, and $3,797 in 2021 through at least April 2021. The Commission observes that the annualized expense for travel to Kentucky in 2021 would be about $11,392.[238]

The Commission finds that travel expenses allocated to Bluegrass Water should be based on travel to, in, and from Kentucky, because those direct travel expenses will provide a more accurate estimate of costs incurred for the benefit of Kentucky customers. In addition, the Commission finds that the portion of travel expenses attributed to travel by business development employees should be removed in their entirety. Therefore, the Commission has reduced CSWR's forecast period travel expense in the SG&A budget by $576,168 and directly allocated the allowable travel expense in the amount of $11,392.

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[237] *See* Response to Staff's Fourth Request, Item 7, 4-PSC-07.xlsx.
[238] $3,797.34 x 12/4 = $11,392.02

h. Management Consulting

CSWR included Management Consulting expense of $243,300 in its itemized budget for the forecast test period.[239] Bluegrass Water was asked, among other things, to provide a list of all of the vendors that provided CSWR Management Consulting services in 2019 and 2020, to identify the costs paid to each vendor, and to explain what services CSWR received in consideration for that cost. Bluegrass Water provided a list of vendors used in the base period[240], but failed to produce an explanation of the services provided by each vendor.[241] Rather, Bluegrass Water identified only broad categories within which the venders allegedly provided services, including accounting support, system consulting, executive support, human resources consulting, communications and public relations consulting, legal and regulatory consulting, and environmental consulting.[242]

The only Management Consulting vendor for which detailed information was provided was Elasticity, which Bluegrass Water projected would be included both as part of direct expenses and allocated expenses from CSWR. However, as discussed above, Bluegrass Water failed to establish why any portion of the cost for Elasticity should be recovered from Bluegrass Water customers, much less why amounts that cannot be tied directly to Bluegrass Water itself should be recoverable.

[239] Response to Staff's Second Request, Item 1(c), 2-PSC-01c.xlsx.
[240] Response to Staff's Third Request, Item 12(b).

[241] *See* Response to Staff's Third Request, Item 12(b)(c); *see also* May 19, 2021 H.V.T. at 16:20:58; Response to Staff's Fourth Request, Item 7c, 4-PSC-07.xlsx (in which Bluegrass Grass was asked to provide a narrative description of the services provided by contractors but did not do so).

[242] *See* Response to Staff's Third Request, Item 12(b)(c).

The Commission also notes that it is unclear whether expenses for certain vendors identified as Management Consulting vendors in historical periods were included elsewhere in the SG&A budget. As noted above, Bluegrass Water indicated that vendors provided “Legal and Regulatory Consulting,” “Accounting Support,” and “Environmental Consulting.” However, the SG&A budget for the forecast period includes separate line items for Legal Fees, Auditor and Accounting Services, and Engineering Consulting, which would seem to cover similar services. Bluegrass Water also included expense for Starnik Systems, Inc., which provided IT services, as a Management Consulting expense in 2019, but also included a line item in the SG&A budget explicitly for IT expenses.

The Commission finds that CSWR did not establish that the Management Consulting vendors provide services for which costs should be allocated to Bluegrass Water’s customers. Thus, the Commission finds that the total amount should be disallowed and has, therefore, reduced CSWR’s forecast period Management Consulting Expense in the SG&A budget by $243,000.

3. Summary of Allocated Overhead Adjustment

The table below reflects the adjustments to the SG&A budget discussed above before business development expense is removed and the SG&A budget is allocated among CSWR’s systems.

Admin & Human Resources	$	4,944,106
Office Supplies and Travel Expense		106,271
Management Consulting		--
Engineering Consulting		20,400
Auditor & Accounting Services		133,000
Legal Fees		87,684
IT		238,250
Rent		168,000

Insurance		77,000
Miscellaneous		6,000
Total Corporate SG&A	$	5,780,711

Application of the sharing percentage discussed above for the allocation of business development expense reduces the SG&A budget to be allocated among CSWR's utilities to $3,837,897.[243] Application of the sharing percentage discussed above for the allocation of the SG&A budget among CSWR's utilities results in overhead to be allocated to Bluegrass Water of $191,136. However, as noted above, the Commission found that travel expense of $11,392 should be allocated directly. Thus, the Commission finds that overhead allocated to Kentucky should be $202,519.

In its application, Bluegrass Water projected $335,961 in allocated overhead for the forecasted test year, of which it allocated $292,902 to its sewer operations, including the 00297 systems, and $43,059 to its water operations based on the customer counts of those systems.[244] For the reasons discussed above, the Commission finds that the total allocated overhead should be reduced to $202,519 in the forecasted period, of which $176,909 would be allocated to sewer operations and $25,610 would be allocated to

[243]

Total Adjusted Corporate SG&A	$	5,780,711
Multiply By: BD Percentage		33.61%
Allocated BD		1,942,814
Total Adjusted Corporate SG&A		5,780,711
Subtract: Allocated BD		1,942,814
Allocatable Corporate SG&A	$	3,837,897

[244] *See* Response to Staff's First Request, Item 1, BGUOC2020RateCase-Schedule_OHA1.xlsx.

water operations using Bluegrass Water's allocation methodology.[245] Thus, the Commission finds that the allocated overhead for sewer operations in the forecasted test period should be reduced by $115,993[246] and that the allocated overhead for water operations in the forecasted test period should be reduced by $17,449.[247]

Adjustment to Remove 2020-00297 Systems

As noted above, the Commission finds that the revenues and costs associated with the 00297 systems should be eliminated when calculating rates and the revenue requirement for the systems at issue here. As discussed above, when determining the rate base for the systems at issue in this case, the Commission did not include any of the elements of rate base for the 00297 systems, such that the return and any taxes on that return only included costs associated with the systems at issue in this case. Further, the Commission applied the depreciation rates discussed above to the rate base that did not include the 00297 systems such that depreciation expense for those systems was not included in the revenue requirement for the systems at issue in this matter.

With respect to sewer expenses or elements of the revenue requirement that were not tied to rate base, namely Bluegrass Water's operation and maintenance expense, the Commission allocated those amounts based on number of residential equivalents provided by Bluegrass Water.[248] The Commission notes that this is the method Bluegrass Water generally used to allocate such expenses when the Attorney General requested a

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[245] *See* BGUOC2020RateCase-Schedule_OHA1.xlsx (showing Bluegrass Water's allocation methodology).

[246] $292,902-176,909=$115,993

[247] $43,059-$25,610=$17,449

[248] Appendix C.

breakdown of rates by system and that such an allocation method would essentially occur by default if the 00297 systems had been included in a unified rate. Moreover, the bulk of Bluegrass Water's expenses or projected expenses were incurred collectively such that they could not be allocated directly. Even operator costs, which is Bluegrass Water's largest expense and arguably could be broken out by contract (the 00297 systems are part of a single contract), are collective, at least in part, because as Bluegrass Water acknowledged at the hearing, the contract costs in the later contracts were lower than the earlier contracts due to the fact that the operator was already providing service to other Kentucky systems. Thus, the Commission finds that allocating the costs not associated with rate base using the customer equivalencies provided by Bluegrass Water is the most reasonable method.

In the forecasted test period, as filed with the application, Bluegrass Water included O&M expenses for sewer totaling $2,049,424.[249] With the adjustments to Allocated Overhead and Administrative Services line items of the sewer O&M expense discussed above, the sewer O&M expenses were reduced to $1,898,956. The sharing percentage for the 00297 systems based on the customer equivalent counts projected by Bluegrass Water would be 21.37 percent. Thus, removal of the O&M expenses attributable to the 00297 systems would further reduce the O&M expense for the systems at issue in this matter by $405,421 to $1,493,535 as follows:

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[249] Those costs were broken down as follows: Sewer Contractor Operations-$1,029,348; Sewer Other Operations-$310,377; Sewer Maintenance-$112,008; Customer Billing Expense-$75,237; Uncollectible Accounts-$8,662; Allocated Overhead-$292,902; Administrative Services-$41,122; Property Insurance-$172,604; Regulatory Expense-$9,230, and PSC Assessment $841.00. Response to Staff's First Request, Item 1, BGUOC2020RateCase-IncomeStatement_(Sewer).xlsx, Tab Inc Statement – SCH C.1.

Category	Sewer O&M-Application	00297 O&M	O&M Systems at Issue
Sewer - Contract Operations	$1,029,348	$219,972	$809,376
Sewer - Other Operations	310,377	66,328	244,049
Sewer - Maintenance	112,008	23,936	88,072
Customer Billing Expense	75,237	16,078	59,159
Uncollectible Accounts	8,662	1,851	6,811
Allocated Overhead	176,909	37,806	139,103
Administrative Services	5,672	1,212	4,460
Property Insurance	172,604	36,886	135,718
Regulatory Expense	6,322	1,351	4,971
PSC Assessment	841	(975)	1816
Total O&M Expenses (Sum of Lines 9-32):	$1,898,956	$405,421	$1,493,535

Uncollectible Accounts.

Applying an uncollectible rate of 0.75 percent to the sewer operating revenues of $908,166 results in a pro forma Uncollectible expense for the sewer division of $6,811. Applying the uncollectible rate to the water operating revenues of $90,000 results in a pro forma Uncollectible expense of $675 for the water division.

Public Service Commission (PSC) Assessment.

Applying the Commissions assessment rate of rate of 0.20 percent to the sewer operating revenues of $908,166 results in a pro forma PSC Assessment expense for the sewer division of $1,816, which is $975 above the forecasted test-year amount. Applying the Commissions assessment rate to the water operating revenues of $90,000 results in a pro forma PSC Assessment expense of $180 for the water division.

Interest Synchronization Expense

In its calculation of income tax expense for the sewer division the Commission has included interest expense of $78,052,[250] based on Bluegrass Water's capital structure, the weighted cost of debt[251] and Bluegrass Water's Rate Base. In its calculation of income tax expense for the sewer division the Commission has included interest expense of $16,899.[252]

Income Tax Expense

Using the pro forma operating revenues and expenses for the sewer division determined reasonable herein, the Commission arrives at its pro forma federal income tax expense of ($113,889), and state income tax expense of ($28,543). The table below is the Commission's calculation of pro forma income tax expense:

[250] $2,601,721 (Rate Base - Sewer) x 3.00% (Weighted Cost of Capital) = $78,052.

[251] 6% (Long-Term Debt Rate) x 50% (Debt Percentage = 3% (weighted Cost of Debt).

[252] $562,971 (Rate Base - Water) x 3.00% (Weighted Cost of Capital) = $16,889.

	Income Tax - Sewer	
	State	Federal
Operating Revenues	$ 908,166	$ 908,166
Operating Expenses:		
Operation & Maintenance Exp.	1,493,535	1,493,535
Depreciation	49,697	49,697
General Taxes	13,856	13,856
State Income Taxes	0	(28,543)
Interest Expense	(78,052)	(78,052)
Total Operating Expenses Before Income Taxes	1,479,035	1,450,492
Taxable Income	(570,869)	(542,326)
Multiplied by: Tax Rates	5%	21%
State and Federal Income Taxes	$ (28,543)	$ (113,889)

Using the pro forma operating revenues and expenses for the water division determined reasonable herein, the Commission arrives at a pro forma federal income tax expense of ($25,037), and state income tax expense of ($6,275). The table below is the Commission's calculation of pro forma income tax expense:

	Income Tax - Water	
	State	Federal
Operating Revenues	$ 90,000	$ 90,000
Operating Expenses:		
Operation & Maintenance Exp.	207,125	207,125
Depreciation	(8,607)	(8,607)
General Taxes	92	92
State Income Taxes	0	(6,275)
Interest Expense	16,889	16,889
Total Operating Expenses Before Income Taxes	215,499	209,224
Taxable Income	(125,499)	(119,224)
Multiplied by: Tax Rates	5%	21%
State and Federal Income Taxes	$ (6,275)	$ (25,037)

PRO FORMA ADJUSTMENTS SUMMARY

The effect of the Commission's adjustments on Bluegrass Water's pro forma test-period operations for the sewer division is below. The chart in Appendix E, attached to this Order, is a detailed water pro forma Income Statement that shows the effect of the Commission's adjustments along with the proposed and accepted adjustments of Bluegrass Water for its sewer division.

Sewer Division

	Bluegrass Water's Forecasted Test Year	Commission Accepted Adjustments	Commission Adjusted Test Year
Operating Revenues	$ 1,154,988	$ (246,822)	$ 908,166
Operating Expenses	2,331,141	(916,486)	1,414,654
Net Operating Income	$ (1,176,153)	$ 669,664	$ (506,488)

The effect of the Commission's adjustments on Bluegrass Water's pro forma test-period operations for the water division is below. The chart in Appendix F, attached to this Order, is a detailed water pro forma Income Statement that shows the effect of the Commission's adjustments along with the proposed and accepted adjustments of Bluegrass Water for its water division.

Water Division

	Bluegrass Water's Forecasted Test Year	Commission Accepted Adjustments	Commission Adjusted Test Year
Operating Revenues	$ 90,000	$ -	$ 90,000
Operating Expenses	286,047	(75,031)	211,016
Net Operating Income	$ (196,047)	$ 75,031	$ (121,016)

RATE OF RETURN

Capital Structure

Bluegrass Water proposes a hypothetical capital structure consisting of 50 percent equity and 50 percent long-term debt. The actual capital structure currently approximates 100 percent equity.[253] Bluegrass Water's witness, Jennifer E. Nelson, states that the current capital structure deviates from standard utility practice as it is disproportionately leveraged in favor of equity.[254] She continues stating that the proposed hypothetical capital structure is within industry norms and investor requirements.[255] She avers that although the proposed capital structure is slightly more leveraged than the proxy groups, the proposed hypothetical capital components fall within the proxy group common equity ratios which range from 43.13 percent to 67.12 percent and a mean of 55.23 percent.[256] Additionally, Ms. Nelson notes that the proposed hypothetical capital structure supports the proposed capital structure approved in the acquisition of several assets in Case Nos. 2019-000104 and 2019-00360.[257] Neither the Attorney General nor the Joint Intervenors filed comments regarding the proposed capital structure debt to equity ratios.

The Commission agrees with Ms. Nelson that the current capital structure deviates from standard utility practices and is inappropriate for ratemaking purposes. As noted by Ms. Nelson, David Parcell's text, the *Cost of Capital Manual*, states that there are circumstances where a hypothetical capital structure is used for a utility such as when the

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[253] Direct Testimony of Jennifer E. Nelson, (Nelson Testimony) at 5.
[254] Nelson Testimony at 5.

[255] Nelson Testimony at 7.

[256] Nelson Testimony at 8.

[257] Nelson Testimony at 7.

current capital structure is deemed substantially different from the typical.[258] Ms. Nelson further notes that in *The Regulation of Public Utilities* by Charles F. Phillip, a hypothetical capital structure is used only when the utility's actual capitalization is clearly out of line as compared to others.[259] Clearly a capital structure that approximates 100 percent equity is not typical nor reasonable. Therefore the Commission finds that a hypothetical capital structure consisting of 50 percent long-term debt and 50 percent equity to be reasonable.

Long-Term Debt Rate

As a component to the hypothetical proposed capital structure, Bluegrass Water proposed a long-term debt rate of 9.50 percent. Ms. Nelson based this debt rate upon the midpoint of then current financing negotiations where the rate was expected to be in the range of 9.00 and 10.00 percent.[260] Ms. Nelson supported a long-term debt rate of 9.50 percent stating that it was reasonable based upon her analysis of the yield curve data on B-rated and CCC-rated utility debt.[261] Ms. Nelson stated that B-rated and CCC-rated utility debt yields are close proxies as they reflect higher risk, below-investment grade utility debt rate costs. As of September 23, 2020, these below-investment grade utility debt yields were in the range of 8.84 to 11.70 percent for terms of 15 years or more. As of January 19, 2021, the range had decreased to 8.42 to 10.63 percent[262] and as of

[258] Nelson Testimony at 6.

[259] Nelson Testimony at 6–7.

[260] Nelson Testimony at 9.

[261] Nelson Testimony at 9.

[262] Bluegrass Water's Response to Staff's First Request for Information, Item 53.

May 16, 2021, the range had increased, but was still below the range at filing of 8.49 to 11.33 percent.[263]

Bluegrass Water filed notice of financing in Case No. 2021-00128 on March 8, 2021.[264] On April 13, 2021, Bluegrass Water filed a status update in Case No. 2021-00128 and the instant case. In this update, Bluegrass Water stated that due to the Commission's March 24, 2021 Order affirming its decision that any rate adjustment would not include the four systems Bluegrass Water had been approved to acquire in Case No. 2020-00297, the lender was reassessing the situation. Bluegrass Water contends that the reasoning for this reassessment is that even if the current rate case is successful, Bluegrass Water will be in a negative net cash flow position due to the additional acquisitions.[265] Bluegrass Water noted that it was approaching other lenders, but has had indications that financing would not be available due to the impact of the exclusion decision.[266] At the hearing, Mr. Cox stated that Bluegrass Water was working with a St. Louis-based lender and was negotiating financing at a debt rate of 6.00 percent and expected to file with the Commission in the next 20–30 days.[267]

The Attorney General asked that the Commission set a long-term debt rate which accurately reflects current market conditions.[268] The Attorney General notes that Ms.

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[263] BW Hearing Exhibit. 01 filed May 21, 2021.

[264] Case No. 2021-00128, *Electronic Application of Bluegrass Water Utility Operating Company, LLC for Approval of Financing Pursuant to KRS 278:300*, (filed Mar. 8, 2021) Notice.

[265] Case No. 2021-00128, (filed April 13, 2021) Notice: re Status of Proposed Application.

[266] *Id*.

[267] May 19, 2021 H.V.T. at 9:35.

[268] Post-Hearing Brief of the Attorney General at 7.

Nelson's argument that the proposed 9.50 percent long-term debt rate was supported by the argument that the distressed nature of the systems increases the cost of debt is no longer relevant due to the many system improvements illustrated in the video shown by Bluegrass Water at the beginning of the Hearing.[269]

The Joint Intervenors also argued against the proposed 9.50 percent long-debt rate noting that the testimony at the hearing demonstrated that the rate environment for debt has improved since the application filing.[270] The Joint Intervenors supported this position by noting that Bluegrass Water agreed that interest rates for similar situated CCC-rated companies were between 6.00 and 6.97 percent.[271]

Bluegrass Water responded that piecemeal updates, such as to the long-term debt rate, fail to uniformly follow applicable principles.[272] In support of this argument, Bluegrass Water stated that it complied with the law when utilizing a forward-looking test period and updates and/or modifications violate principles of KRS 278.192.[273] Bluegrass Water contends that it provided a full and accurate application in support of the requested rates and not pieces here and there that fail to provide support of the application in full and selecting updates of certain elements upsets the balance contemplated by guidelines used for a forecasted test period.[274] Bluegrass Water maintains that a 9.50 percent long-

[269] *Id.*

[270] Post-Hearing Brief of Joint Intervenors at 16.

[271] Post-Hearing Brief of Joint Intervenors at 16.

[272] Post-Hearing Response Brief of Bluegrass Water at 7.

[273] Post-Hearing Response Brief of Bluegrass Water at 7.

[274] Post-Hearing Response Brief of Bluegrass Water at 8.

term debt rate reflects the risks associated with small, distressed utilities that have difficulty attracting traditional financing and should not be altered to reflect a lower amount due to perceived fluctuations in the market.[275]

The Commission finds that the rate represented by Mr. Cox of 6.00 percent to be reasonable. The Commission agrees that higher risk utility bonds can be used as a gauge for the determination of the long-term debt rate, but when determining a proxy for the long-term debt rate, the Commission must also assess the current lending market, the regulatory environment, and other comparable investments. Current rates for BBB and CCC rated corporate bonds are 2.410 and 6.974 percent, respectively.[276] These BBB and CCC rated corporate bonds are often referred to as junk bonds or a non-investment grade high risk security. Bluegrass Water's expert, Mr. Dylan D'Ascendis, agreed that utility bonds are issued in a regulated world, hence carry less risk than a low rated corporate bond and thus typically have a lower yield.[277] The Commission-approved 6.00 recognizes the additional risk associated with Bluegrass Water as the 6.00 percent is within the upper range of similar high-risk corporate investments.[278] Further, with a long-term debt rate of 6.00 percent, the Commission recognizes the additional risk of Bluegrass Water as compared to larger utilities in that the rate is greater than the

[275] Post-Hearing Response Brief of Bluegrass Water at 8.

[276] *See* May 19, 2021 H.V.T. at 13:50:00 (displaying and discussing bond rates reported by the Wallstreet Journal on May 18, 2021).

[277] May 19, 2021 H.V.T. at 13:30:00.

[278] May 19, 2021 H.V.T. at 14:00:00.

Commission's most recently approved long-term debt rate of 3.89 percent[279] and current forecasted filings of 4.16 percent[280] and 4.04.[281]

Return on Equity (ROE)

Bluegrass Water proposed a ROE of 11.80 percent. Mr. D'Ascendis' models included the discounted cash flow model (DCF), two risk premium models (RPM), a capital asset pricing model (CAPM), and a comparison of common equity cost rates for a proxy group of domestic, non-price regulated companies based upon the DCF, RPM, and CAPM. Using a proxy group of seven water utilities and forecasted interest rates, the proposed range of equity cost rates were 9.74 to 10.41 percent. Mr. D'Ascendis then applied a business risk adjustment of 1.75% increasing the proposed range to 11.49 percent to 12.16 percent.

In D'Ascendis' evaluation of the capital market, he emphasized that the COVID-19 pandemic has increased risk due to the uncertainty surrounding the full impact and duration of the pandemic.[282] He continued, stating that the increased volatility in the market is the cause of lower bond prices, as opposed to the low interest rate environment, and this same market volatility is contributing to investor's "flight to safety" which creates

[279] Case No. 2020-00174, *Electronic Application of Kentucky Power Company for (1) A General Adjustment of Its Rates for Electric Service; (2) Approval of Tariffs and Riders; (3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; (4) Approval of a Certificate of Public Convenience and Necessity; and (5) All Other Required Approvals and Relief* (Ky. PSC Jan. 13, 2021) at 40.

[280] Case No. 2020-00349, *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates, a Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-year Surcredit* (filed Nov. 25, 2020), Application, Direct Testimony of Daniel K. Arbough at 23.

[281] Case No. 2020-00350, *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric Rates, a Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-year Surcredit* (filed Nov. 25, 2020), Application, Direct Testimony of Daniel K. Arbough at 24.

[282] Direct Testimony of Dylan W. D'Ascendis (D'Ascendis Testimony) at 7.

a situation where utilities are traded similar to the S&P 500 and increase Beta coefficients and investor-required returns.[283] The proposed business risk model is akin to a size premium adjustment and D'Ascendis recommended it based upon Bluegrass Water's size relative to the proxy group.[284] D'Ascendis argued that smaller companies are generally more risky as they face more exposure to business cycles and economic conditions.[285]

Below is a summary of D'Ascendis's models:[286]

Table 1: Summary of Common Equity Cost Rate

	Utility Proxy Group
Discounted Cash Flow Model	9.07%
Risk Premium Model	10.88%
Capital Asset Pricing Model	10.96%
Cost of Equity Models Applied to Non-Price Regulated Proxy Group	10.71%
Indicated Range of Common Equity Cost Rates before Adjustment	9.74% - 10.41%
Business Risk Adjustment	1.75%
Indicated Range of Common Equity Cost Rates after Adjustment	11.49% -12.16%
Recommended Common Equity Cost Rate	11.80%

The Attorney General asked that the Commission refrain from awarding Bluegrass Water a ROE of 11.80 percent and instead set a ROE reflective of current market conditions.[287] The Attorney General argued that the proposed ROE was significantly

[283] D'Ascendis Testimony at 7.

[284] Bluegrass Water's Response to Staff's First Request for Information, Item 45.

[285] D'Ascendis Testimony at 46.

[286] D'Ascendis Testimony at 6.

[287] Post-Hearing Brief of the Attorney General at 5.

higher than the model results, specifically the DCF results of 9.07.[288] The Attorney General noted that the reason for the proposed business risk adjustment of 1.75 percent was business and financial risk and should be disregarded. Regarding business risk, the Attorney General argued that this proposed adjustment ignores that fact that the proxy group utilities face similar legal and regulatory environmental risks and as such, returns associated with business risk are already embedded within the proxy group.[289] He continued, noting that D'Ascendis' arguments regarding regulatory risk were centered around water utilities and not wastewater utilities and thus not applicable since all but one of the systems Bluegrass Water currently operates are wastewater.[290] Finally, the Attorney General argues that D'Ascendis' reasoning that Bluegrass Water's sheer size justifies such an adjustment is not warranted.[291] The Attorney General encouraged the Commission to consider the fact that although Bluegrass Water itself is small, but the parent company is not, and, when setting an appropriate rate of return, the Commission should consider the true scope of the company's operations not simply the capitalization of the relatively new venture in the Commonwealth.[292]

The Joint Intervenors also oppose the proposed business adjustment risk adjustment. They argued that Bluegrass Water has failed to demonstrate that such a premium is necessary to attract investment noting that, to date, Bluegrass Water has not

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[288] Post-Hearing Brief of the Attorney General at 5.

[289] Post-Hearing Brief of the Attorney General at 5.

[290] Post-Hearing Brief of the Attorney General at 5–6.

[291] Post-Hearing Brief of the Attorney General at 6.

[292] Post-Hearing Brief of the Attorney General at 6.

had an issue attracting equity as currently, even though the business plan indicates a loss for a period of time, the utility is fully capitalized.[293] The Joint Intervenors maintained that Bluegrass Water has no analysis to support its contention that its business is any more risky than other similarly situated companies in the market and noted that not only is its product essential but the fact since its customers are primarily residential in nature, a loss of a customer will not result in a significant financial impact.[294]

In response, Bluegrass Water continued its argument that selecting particular rate components, such as the ROE, should be avoided.[295] Bluegrass Water contends that the inclusion of the proposed business risk adjustment and the resulting proposed ROE of 11.80 percent is applicable to a utility such as Bluegrass Water due to its size and risk, such an ROE supported the market conditions when the application was filed and any adjustments in the market since the filing should not be considered.[296]

The Commission agrees that there is additional risk associated with Bluegrass Water, not necessarily because of its size but due to the fact that the utility has acquired small, failing systems that require capital improvements for both regulatory purposes and daily operations. However, a ROE of 11.80 percent is not reflective of the current market conditions. For example, an analysis of a small cap water utility in the April 2021 issue of *Value Line* indicates that in 2019 a ROE of 9.30 percent was earned and 9.90 percent

[293] Post-Hearing Brief of Joint Intervenors at 16.

[294] Post-Hearing Brief of Joint Intervenors at 16.

[295] Post-Hearing Response Brief of Bluegrass Water at 9.

[296] Post-Hearing Response Brief of Bluegrass Water at 9.

in 2020;[297] and recent Commission awards, although for electric, have been 9.25[298] and 9.30 percent.[299] Further, a business risk or size adjustment has not been approved in the past and the Commission agrees with the Attorney General and the Joint Intervenors that the explicit inclusion is not reasonable as such an adjustment is arbitrary and inflates the model results. The Commission also notes that it does not support Mr. D'Ascendis' indicated range of common equity cost rates where he calculated the low end of the range by taking the average model result and averaging that with the lowest model results. The Commission believes that ignoring low end model results without support for the exclusion purposely inflates the model. Finally, the Commission rejects Bluegrass Water's argument that selecting components of the application and adjusting them violates the principles of a forecasted test year application. In each filed rate case, the Commission evaluates all components which comprise the overall revenue requirement and applies applicable adjustments for which the Commission deems reasonable and results in rates that are fair, just and reasonable.

The Commission finds that a ROE of 9.90 percent for Bluegrass Water to be reasonable in this matter. This ROE is within Bluegrass Water's own models as the

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[297] *See* Notice of Filing (Ky. PSC Jun. 8, 2021) (containing the relevant pages of The Value Line Investment Survey, Issue 9, Part 2, dated April 9, 2021); *see also* May 19, 2021 H.V.T. at 14:03:00 (where the pages were discussed at the hearing in confidential session).

[298] See Case No. 2019-00271, *Electronic Application of Duke Energy Kentucky, Inc. for 1) an Adjustment of the Electric Rates; 2) Approval of New tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief* (Ky. PSC April 29, 2020) at 46.

[299] *See* Case No. 2020-00174, *Electronic Application of Kentucky Power Company for (1) A General Adjustment of Its Rates for Electric Service; (2) Approval of Tariffs and Riders; (3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; (4) Approval of a Certificate of Public Convenience and Necessity; and (5) All Other Required Approvals and Relief* (Ky. PSC Jan. 13, 2021) at 50.

results range from 9.07 to 10.96 percent. The approved ROE also recognizes the unique risk associated with Bluegrass Water's business model, as it is higher than recent awards, but is also reflective of the current economic environment. Much of Mr. D'Ascendis' argument for the proposed ROE range centers around the uncertainly surrounding the COVID-19 pandemic and the resulting volatility.[300] Since the application filing, market volatility, as measured by the VIX substantially leveled and in May 2021, was near the 30-year historical average.[301] Additionally, the uncertainty surrounding the COVID-19 pandemic has been tempered due to the vaccine roll out and the economy re-opening.

<u>Rate of Return Summary</u>

Applying the rates of 6.00 percent for long-term debt and 9.90 percent of common equity to the approved capitalization produces and overall cost of capital of 7.95 percent.

<u>REVENUE REQUIREMENTS</u>

<u>Authorized Increase - Sewer</u>

The Commission finds that Bluegrass Water's net operating income for rate-making purposes is $206,837. We further find that this level of net operating income requires an increase in forecasted present rate revenues of $959,583.

[300] D'Ascendis Testimony at 7–13; Bluegrass Water's Response to Staff's First Request, Item 38.

[301] *See* D'Ascendis' Testimony at 9, where the VIX has averaged 19.39 since 1990 and Bluegrass Water's Response to Staff's Post Hearing Data Request, Item 3 where the May 1, 2021 average monthly VIX was 20.31.

Net Investment Rate Base - Sewer	$	2,601,721
Multiplies by: Weighted Cost of Capital		7.95%
Operating Income Requirement		206,837
Less: Operating Income at Present Rates		(506,488)
Operating Income Deficiency		713,325
Multiplied by: Revenue Conversion Factor		1.3452
Increase in Revenue Requirement - Sewer	$	959,583

Authorized Increase - Water

The Commission finds that Bluegrass Water's net operating income for rate-making purposes is $44,756. We further find that this level of net operating income requires an increase in forecasted present rate revenues of $223,001.

Net Investment Rate Base - Water	$	562,971
Multiplies by: Weighted Cost of Capital		7.95%
Operating Income Requirement		44,756
Less: Operating Income at Present Rates		(121,016)
Operating Income Deficiency		165,773
Multiplied by: Revenue Conversion Factor		1.3452
Increase in Revenue Requirement - Water	$	223,001

Unified Rate

Bluegrass Water proposes a unified, monthly flat rate for all residential wastewater customers, multi-family, and commercial customers based on a residential equivalency of $96.14, $72.11, and $240.36, respectively.[302] For its water customers, Bluegrass

[302] Application Exhibit 3.

Water proposes to increase the current monthly flat rate from $22.79 to $105.84.[303] The proposed monthly flat rate design was adopted by Bluegrass Water as it mimics the rate design of the former individual systems it acquired.[304]

The Attorney General did not provide comments concerning the proposed unified monthly flat rate design but did request that such a large rate increase be phased in gradually to minimize rate shock.[305]

The Joint Intervenors argue that the proposed unified rate design for the wastewater customers creates unfair subsidization.[306] Customers of systems that need little or no capital expenditures to maintain proper service will subsidize the major repairs and rehabilitation of the distressed systems Bluegrass Water has acquired. The Joint Intervenors state that a unified rate may be an appropriate goal over time; however, it is unfair, unjust and unreasonable to move to a unified rate in a single proceeding.[307] The Joint Intervenors propose a limiting factor to the amount of any single system's capital expense can be shared with customers from other systems, which can then be revised in subsequent cases.[308] Bluegrass Water argues that eventually each of the systems will require significant capital investment; therefore, the customers are better served by the

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[303] *Id.*

[304] Application at 5.

[305] Post-Hearing Brief of Attorney General at 8.

[306] Post-Hearing Brief of Joint Intervenors at 17.

[307] *Id*.

[308] *Id*.

proposed unified rate.[309] Bluegrass Water states the proposed unified rate will allow for the financial burdens common to all systems to be distributed in a beneficial manner to each of the ratepayers, and allow the systems—which are historically distressed—to be brought into and kept in compliance and to continue providing safe and reliable service.[310] Bluegrass Water states that the Commission has consistently supported a unified rate structure to encourage consolidation of systems to improve the quality of service in the Commonwealth.[311]

The Commission supports the principle that utility rates should be cost based, and that in most circumstances each class of utility ratepayers should pay the costs which the utility incurs to provide that class with utility service. The majority of Bluegrass Water's customers are in the residential class. A separate rate for each geographically distinct merged system of Bluegrass Water would create unreasonable and undue hardship to individuals in some areas served by Bluegrass Water. The Commission finds that the proposed unified monthly flat rate design, with wastewater multi-family dwellings and commercial customers monthly rates based on residential equivalency, should be approved for Bluegrass Water's customers.

Nonrecurring Charges

The Commission has reviewed Bluegrass Water's current and proposed Nonrecurring Charges for both the water operations and the sewer operations. Bluegrass

[309] Cox Testimony at 72–73.

[310] Post-Hearing Response Brief of Bluegrass Water at 7.

[311] *Id.*

Water has not provided cost justification supporting the current charges or the proposed charges for either water operations or the sewer operations.[312] In support of these charges, Bluegrass Water states that the new Nonrecurring Charges are to recover costs incurred by Bluegrass Water. For the current Nonrecurring Charges, Bluegrass Water maintains that the previous utility instituted these and they do not know what cost justification was presented when the charges were established.[313] In addition, Bluegrass Water did not provide any forecasted occurrences for the current Nonrecurring Charges for water customers or proposed Nonrecurring Charges for sewers customers as requested.[314] Because no costs have been identified in support of these Nonrecurring Charges, the charges have been reduced to zero. If Bluegrass Water desires to charge Nonrecurring Charges in the future, Bluegrass Water should file a request through the Commission's Electronic Tariff Filing System and provide all cost justification and supporting documentation for these charges.[315]

<u>Tap Fees</u>

Bluegrass Water proposed a Tap Fee for all of its sewer systems of $750.00. Currently, Bluegrass Water charges Tap Fees for four sewer systems: Arcadia Pines, $500.00; Great Oaks, $750.00; Golden Acres, $250.00; and Marshall Ridge, $500.00. Bluegrass Water has a Water Tap Fee of $350.00 and has not requested to adjust this fee in its application. Like the non-recurring charges, Bluegrass Water did not provide

[312] Staff's Fourth Request for Information (filed Apr. 29, 2021), Items 1 and 3.

[313] Bluegrass Water's Response to the Commission Staff's Fourth Request for Information (filed May. 29, 2021), Items 1 and 3.

[314] *Id.*, Items 2 and 4.

[315] *See*, 807 KAR 5:011, Section 10.

cost justification for either the current Water Tap Fee or the proposed Sewer Tap Fee, and maintained that the proposed Tap Fees recover only a fraction of the costs incurred by Bluegrass Water.[316] The Commission finds that the proposed Sewer Tap Fee of $750.00 should be denied; but, the current tariffed Water and Sewer Tap Fees should be allowed to continue to be charged. If Bluegrass Water desires to charge a unified Sewer Tap Fee, Bluegrass Water should file a request through the Commission's Electronic Tariff Filing System and provide all cost justification and supporting documentation.

SUMMARY

The Commission, after consideration of the evidence of record and being otherwise sufficiently advised, finds that:

1. The rates set forth in Appendix B to this Order are the fair, just and reasonable rates for Bluegrass Water to charge for service rendered on and after the date of this Order.

2. The rate of return granted herein is fair, just and reasonable and will provide sufficient revenue for Bluegrass Water to meet its financial obligations with a reasonable amount remaining for equity growth.

3. The rates proposed by Bluegrass Water would produce revenue in excess of that found reasonable herein and should be denied.

IT IS THEREFORE ORDERED that:

1. Bluegrass Water's request for a declaratory order finding that the construction on Airview's wastewater treatment facility; the project to replace Brocklyn's wastewater treatment facility; construction on Delaplain's wastewater treatment facility;

[316] *Id.*, Item 3.c.

construction on River Bluffs' wastewater treatment facility; and construction of the Mission monitoring systems is denied based on the Commission's finding that a CPCN is or was required for that construction.

2. The Commission, exercising its discretion pursuant to 807 KAR 5:001, Section 19(1), declines to make a specific finding regarding whether each additional construction item proposed by Bluegrass Water requires a CPCN and, therefore, denies Bluegrass Water's request for a declaratory order finding that those construction items do not require CPCN.

3. Bluegrass Water's request for a CPCN is granted with respect to the construction on Airview's wastewater treatment facility that has not been completed, and it is denied with respect to the construction that has been completed.

4. Bluegrass Water's request for a CPCN is denied with respect to the project to replace Brocklyn's wastewater treatment facility; construction on Delaplain's wastewater treatment facility; construction on River Bluffs' wastewater treatment facility; and construction of the Mission monitoring systems.

5. The rates and nonrecurring charges proposed by Bluegrass Water are denied.

6. The rates in Appendix B to this Order are approved for service rendered by Bluegrass Water on and after the August 1, 2021 for the systems at issue in this matter.

7. The rates of the 00297 systems shall continue to be charged in accordance with the tariffs sheets for those systems filed on or about April 5, 2021, until a subsequently filed tariff proposing to amend those rates is filed pursuant to KRS Chapter 278 and 807 KAR Chapter 5.

8. Within 20 days of the date of this Order, Bluegrass Water shall file with the Commission, using the Commission's Electronic Tariff Filing System, new tariff sheets setting forth the rates, charges, and revisions approved herein.

9. Bluegrass Water's March 22, 2021 motion for an enlargement of time to March 26, 2021, to respond to the Commission's Staff's Third Request for Information is granted.

10. Absent a request for rehearing, this case will be closed and removed from the Commission's docket upon expiration of the statutory time period to request rehearing.

By the Commission

Vice Chairman Kent A. Chandler
dissenting in part

ENTERED

AUG 02 2021 bsb

KENTUCKY PUBLIC
SERVICE COMMISSION

ATTEST:

for
Executive Director

<u>Opinion of Vice Chairman Kent A. Chandler in Case No. 2020-00290, Concurring In Part and Dissenting In Part</u>

Although I appreciate the Majority's well-written and exhaustive Order, particularly given the complexity of the matter before us, I must write separately to dissent in significant part regarding the Order's conclusion and rates. Before explaining the reason for which I dissent, I note that I concur on a number of items in the Majority's Order. I concur with the Majority insofar as they reaffirm the Commission's previous decisions denying the inclusion of the 00297 systems as part of this request to increase rates.[1] I also concur with the Majority's decision regarding "Procedural Issues."[2] Finally, I find no error with the Majority Order's determinations with regard to Certificates of Public Convenience and Necessity and the adoption of a unified tariff, generally.[3]

Regretfully, my ability to concur with the Majority's Order ends there. Instead of approving the rates found in the Majority's Order as fair, just and reasonable, I would have voted to order no change to Bluegrass Water's present rates, due to the utility's failure to (1) provide reasonable, sufficient or competent financial information, (2) provide the information necessary to appropriately calculate a revenue requirement, and (3) generally meet its burden of proof as to its proposed rates. Although Bluegrass Water is aware of the components of rate base[4] and how to calculate it, including the calculation

[1] Majority Order at 3-4, 10-13. *See also* March 24, 2021 Order denying Bluegrass Water's Motion to Alter the Commission's 2/12/21 Order; February 12, 2021 Order denying Bluegrass Water's November 18, 2020 Motion for Deviation from Requirements relating to Customer Notice.

[2] Majority Order at 14-15.

[3] *Id*. at 15-38.

[4] Direct Testimony of Brent G. Thies at 12-13.

of Utility Plant in Service (UPIS),[5] as the Majority's Order discusses, the information provided by the utility was incomplete, contrary to other sources, and wholly deficient for purposes of determining rate base. Bluegrass Water failed to provide a reasonable or competent amount for UPIS by failing to reflect any amount for asset retirements,[6] and failing to adequately explain discrepancies in its forecasted CWIP and UPIS calculations.[7] Rate base is of course a foundational component of the calculation of a utility's revenue requirement. Net investment rate base is necessary to determine a utility's operating income and depreciation expense. With a net investment rate base of $0, for instance, a utility's revenue requirement is equal to operating expenses, while the operating expenses would include no depreciation expense. Once it was concluded that Bluegrass Water had not provided competent support or explanation for the determination of rate base, I would have found the application deficient to the point fair, just and reasonable rates could not be determined from the record. This determination would be in accordance and pursuant to KRS 278.190(3), wherein the controlling statute clearly notes "the burden of proof to show that the increased rate or charge is just and reasonable shall be upon the utility." Failure by the utility to meet its burden of proof should result in no increase in rates.

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[5] *Id*. at 12-15.

[6] *See* Majority Order at 44-46, wherein the majority notes that the "undisputed evidence indicates Bluegrass Water did not include any retirements in the base period, the forecasted test year, or the period between the base and forecasted periods despite providing sworn testimony with its application that it had done so," and the Majority Order goes on to discuss why doing so was results oriented to the utility's benefit and was unreasonable.

[7] Majority Order at 44.

Nevertheless, the derivation and presentation of rate base is not the only issue for which I would have determined the utility failed to meet its burden of proof regarding its proposed rates. Bluegrass Water provided incorrect or inconsistent amounts for depreciation[8], Business Development,[9] and "Admin and Human Resources" expenses.[10] Bluegrass Water's compensation is unreasonable, unsubstantiated and lacks and formal policy.[11] The only basis provided for current levels of compensation or for increases, including CSWR's CEO's nearly 30% raise, was contradicted by the evidence of record.[12]

During the pendency of this matter Bluegrass Water has spent significant time, effort, and expense explaining its inconsistent or incomplete case record. Nearly all of these issues are related to the organization's finances or management, not necessarily Bluegrass Water's prosecution of the case. Bluegrass Water is the master of its petition. It chose when and how to file its application in this matter. It further determined the water and wastewater systems it sought to purchase, and after purchase, the amount of investment it intended on making before, during, and after its proposed test year; a time period the utility was further in control of determining in its application. Bluegrass Water came into the Commonwealth claiming it intended to "professionaliz[e] distressed"

[8] Majority Order at 46, 66-67.

[9] Majority Order at FN 183.

[10] Majority Order at 82-83.

[11] Majority Order at 86, FN 217 citing Bluegrass Water's Response to Commission Staff's Second Request, Item 24.

[12] See Majority Order at 86-87, stating "Bluegrass Water further argued that 'CSWR seeks to attract the most qualified individuals and views total compensation, including the benefits package, as key to achieving that goal,'" while later noting CSWR did not review peer employers when determining employer insurance contributions and that neither Bluegrass Water nor CSWR "performed a study to compare its wages, salaries, benefits, and other compensation to other similarly-situated companies."

utilities. As explained herein and as detailed in the Majority's Order, the support provided for the utility's proposed application and rate increase failed to satisfy Bluegrass Water's burden of proof and falls short of what should be expected from an organization of Bluegrass Water's stature. It should not fall to the utility's attorney or the Commission to rectify or explain away an applicant's material shortcomings related to the financial information provided as support for a rate increase.

Finally, with regard to Bluegrass Water and this application, I must note that none of the systems owned by the utility now was without issue at their time of transfer to Bluegrass Water. A few of the orders approving either the transfer of jurisdictional systems to Bluegrass Water or the initiation of service under KRS 278.020 of previously non-jurisdictional systems indicated the problems or condition of the current service. The Majority's Order discussed this reality in sections, noting the obligation of Bluegrass Water to enter into Agreed Orders with the Commonwealth's Energy and Environment Cabinet to cure identified deficiencies. Upon review of the systems Bluegrass Water has acquired over the past two years, I would note that most of them are older, in poor operating condition, have generally lacked recurring maintenance and require (or have required for years) significant capital investments to provide adequate service. Regardless of who purchased many of these systems, rehabilitations will need to be made in order to continue providing service. Given the size of those systems, some sort of consolidation or regionalization is likely necessary to simultaneously provide adequate service at affordable rates. I take no position on Bluegrass Water's business model at this time, but I would note that to-date I have yet to see the type of "economies of scale and scope that can sustain and improve existing service" and a rate that appears to me as being fair, just or reasonable.[13]

I further write today to explain the systemic shortcomings this case has served to elevate. During the pendency of this matter, the Commission received a number of comments on the application, including those from elected officials. Public comments ranged from general concern about the ability to pay for the proposed increase, to questions of whether investments underlying the rate increase were reasonable or necessary. Many of the comments request the Commission take specific action on the application, such as considering the affordability of the proposal or the sheer increase of the application. As a practical matter, two factors are at play that complicate the Commission's ability to make much meaningful impact on applications like the one at hand, short of a finding the utility merely has not met its burden of proof. Regretfully, these two factors exacerbate one another.

The first complicating factor is the lack of evidence before us. Short of finding an applicant has failed to meet their burden of proof, the Commission often depends on record evidence other than the applicant's to make findings of fact contrary to the utility's proposal. In this matter, neither intervening party, the Attorney General,[14] nor the Joint

[13] Verified Joint Application for Approval of Acquisition and Transfer of Ownership and Control of Utility Assets, Case No. 2019-00104 (Apr. 16, 2019) at 23.

[14] These statements should not be construed as a critique of the Attorney General's Office of Rate Intervention (ORI), or the Attorney General. My personal experience and understanding is that the resources available for the purpose of participating before the Commission have been limited for decades. The Attorney General's ORI has historically been staffed exclusively by attorneys, rather than staff rate experts that can offer testimony. Further, consultant witnesses that have experience in rate matters are not inexpensive. Again, these comments are merely illustrative of a current example. The Attorney General's ORI has occasionally experienced the same resource constraints as I detailed for the Commission below.

Intervenors provided much in the way of alternative evidence. This is not to say that either of the parties failed to play a meaningful role in the matter. Indeed, the Majority's Opinion cites a number of arguments made by both parties that it agreed with, and cited a number of times to responses to intervenor discovery requests in support of its conclusions and rationale. However, discovery and arguments can only go so far in determining fair, just and reasonable rates. Evidence is the lifeblood of administrative decisions, including those made by this Commission. One needs only review the statute and case law in regard to judicial review of Commission orders to appreciate the importance of evidence. Commission orders may only be vacated or set aside if they are found to be unreasonable or unlawful, and an order is unreasonable "only if it is determined that the evidence presented leaves no room for difference of opinion among reasonable minds."[15] Without contrary "affirmative" evidence, such as intervenor testimony, and other than a finding the applicant failed to meet its burden of proof, the Commission is limited in its ability to effectuate much change in an applicant's proposed rates. The only additional tool the Commission has at its discretion is its experience, case precedence and dedicated staff. Staff and Commission resources though are not what they used to be.

The Commission currently has approximately 70 employees, including the Commissioners. These employees include those that actively and substantively work on open matters, like financial analysts and attorneys, as well as staff that support the Commission's work, such as IT professionals and consumer service representatives. In

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[15] KRS 278.410; *Kentucky Industrial Utility Customers, Inc. v. Kentucky Utilities Company*, 983 S.W.2d 493, 499, citing *Energy Regulatory Commission v. Kentucky Power, Ky. App., 605 S.W.2d 46 (1980).*

cases such as this one, the Commission depends on its staff to help investigate the reasonableness of the application. Commission Staff's work on these cases is invaluable, and their efforts are exactly what the General Assembly envisioned decades ago in providing the Commission an opportunity to have full-time staff that work exclusively on utility matters. Specifically, the Commission is authorized by the following statute to hire and employ competent staff to help it "perform the duties and exercise the powers conferred by law upon the Commission,"[16] including limiting the rates charged by utilities to only those that are "fair, just and reasonable."[17]

> The commission acting through the executive director may employ such clerks, stenographers, rate experts, agents, special agents, engineers, accountants, auditors, inspectors, lawyers, hearing examiners, experts and other classified service employees and the commission may contract for services of persons in a professional or scientific capacity to make or conduct a hearing or a temporary or special inquiry, investigation or examination as it deems necessary to carry out the provisions of this chapter, or to perform the duties and exercise the powers conferred by law upon the commission.[18]

Nevertheless, in the absence of the "affirmative" evidence discussed above, the Commission depends more and more on its Staff to help investigate and analyze whether applications should approved, modified or revoked. Outright approval or denial of a proposal poses fewer complications than that of a modification, which are ordinarily made in the public interest. The Commission could outright revoke every petition before it that has a minor issue or concern, indicating the reason for denial with an opportunity for the

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[16] KRS 278.110.

[17] KRS 278.030.

[18] KRS 278.110.

applicant to refile. Doing so though would cause untold inefficiency and ultimately not result in any public benefit. Therefore, the Commission has for decades, likely since its inception, made material and substantive modification to proposals in order to ultimately grant their approval. This has proven to be effective and efficient. Nevertheless, without "affirmative" evidence, the Commission depends on its and its Staff's expertise and experience to examine whatever evidence is in the record in order for the Commission to say what is fair, just and reasonable when a proposal before it is facially unfair, unjust or unreasonable. The problem the Commission finds itself in is that with more cases, and more complicated cases, coming before us, we have less staff than ever. During fiscal year 2013, for instance, the Commission employed an average 88 individuals with a personnel funding cap of 98 positions. As noted above, today we find ourselves with approximately 70 staff members, with a funding cap of 76 positions. Frankly, each year the Commission Staff is asked to do more with less.

It is cases like this that the lack of "affirmative" evidence by intervenors and the strain on Commission Staff is most evident. The Majority's Order in this case is as long, or longer than, investor-owned electric and gas rate case orders for utilities with tens-of-thousands of customers and hundreds-of-millions of dollars in annual revenues. This is a complicated case. Without intervenor testimony, for instance, the Commission is limited in its ability to make a meaningful effort to ensure rates are fair, just and reasonable. The Commission cannot merely dismiss a proposal as being "too high," or result in rates that are "unaffordable," particularly given that neither assertion is supported by record evidence. The issue is not KRS Chapter 278 either. The statutes the Commission operates under are adequate on this topic. The issue, insofar as commenters and the public seek to have the Commission play a more active role in ensuring rates are fair, just and reasonable, or service is adequate, efficient and reasonable, is a lack of resources. More resources must be dedicated to (1) providing as much evidence as possible for the Commission to consider and (2) ensuring the Commission and its Staff have the time and personnel to investigate and adjudicate proposals and make decisions in the public's interest. This can be accomplished in a number of ways, including funding, subject to Commission approval, of intervenor witness expense and merely increasing Commission Staff counts to previous levels.

Vice Chairman Kent A. Chandler
dissenting in part

ENTERED

AUG 02 2021

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KENTUCKY PUBLIC
SERVICE COMMISSION

ATTEST:

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2020-00290 DATED AUG 02 2021

13-Month Average UPIS - Sewer

	Total Estimated Project Budget	Estimated Project Start Date	Estimated Project End Date	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	13-Month Average UPIS
Air view	$ 325,436	Sep-20	Sep-21	$ -	$ -	$ -	$ -	$ -	$ 325,436	$ 325,436	$ 325,436	$ 325,436	$ 325,436	$ 325,436	$ 325,436	325,436	$ 200,269
Moitoring System	$ (10,000)	Sep-20	Sep-21	0	0	0	0	0	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	(6,154)
Brocklyn	266,388	Sep-20	Sep-21	266,388	266,388	266,388	266,388	266,388	266,388	266,388	266,388	266,388	266,388	266,388	266,388	266,388	266,388
Moitoring System	(10,000)	Sep-20	Sep-21	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)
Fox Run	232,660	Sep-20	Sep-21	0	0	0	0	0	232,660	232,660	232,660	232,660	232,660	232,660	232,660	232,660	143,175
Moitoring System	(22,000)	Sep-20	Sep-21	0	0	0	0	0	(22,000)	(22,000)	(22,000)	(22,000)	(22,000)	(22,000)	(22,000)	(22,000)	(13,538)
Kingswood	101,764	Sep-20	Sep-21	0	0	0	0	0	101,764	101,764	101,764	101,764	101,764	101,764	101,764	101,764	62,624
Moitoring System	(11,000)	Sep-20	Sep-21	0	0	0	0	0	(11,000)	(11,000)	(11,000)	(11,000)	(11,000)	(11,000)	(11,000)	(11,000)	(6,769)
Lake Columbia	216,005	Sep-20	Sep-21	0	0	0	0	0	216,005	216,005	216,005	216,005	216,005	216,005	216,005	216,005	132,926
Moitoring System	(10,000)	Sep-20	Sep-21	0	0	0	0	0	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	(6,154)
Canceled Projects	(85,000)	Sep-20	Sep-21	0	0	0	0	0	(85,000)	(85,000)	(85,000)	(85,000)	(85,000)	(85,000)	(85,000)	(85,000)	(52,308)
LH Treatment	115,581	Sep-20	Sep-21	0	0	0	0	0	115,581	115,581	115,581	115,581	115,581	115,581	115,581	115,581	71,127
Moitoring System	(7,500)	Sep-20	Sep-21	0	0	0	0	0	(7,500)	(7,500)	(7,500)	(7,500)	(7,500)	(7,500)	(7,500)	(7,500)	(4,615)
Golden Acres	145,828	Sep-20	Sep-21	0	0	0	0	0	145,828	145,828	145,828	145,828	145,828	145,828	145,828	145,828	89,740
Moitoring System	(15,000)	Sep-20	Sep-21	0	0	0	0	0	(15,000)	(15,000)	(15,000)	(15,000)	(15,000)	(15,000)	(15,000)	(15,000)	(9,231)
Great Oaks	95,518	Sep-20	Sep-21	0	0	0	0	0	95,518	95,518	95,518	95,518	95,518	95,518	95,518	95,518	58,780
Moitoring System	(10,000)	Sep-20	Sep-21	0	0	0	0	0	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	(6,154)
River Bluffs	456,151	May-20	Sep-21	0	0	0	0	0	456,151	456,151	456,151	456,151	456,151	456,151	456,151	456,151	280,709
Over Budget	(305,632)	May-20	Sep-21	0	0	0	0	0	(305,632)	(305,632)	(305,632)	(305,632)	(305,632)	(305,632)	(305,632)	(305,632)	(188,081)
Moitoring System	(18,000)	May-20	Sep-21	0	0	0	0	0	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(11,077)
Persimmon Ridge	175,167	Sep-20	Sep-21	0	0	0	0	0	175,167	175,167	175,167	175,167	175,167	175,167	175,167	175,167	107,795
Moitoring System	(40,000)	Sep-20	Sep-21	0	0	0	0	0	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(24,615)
Timberland	252,169	Sep-20	Sep-21	0	0	0	0	0	252,169	252,169	252,169	252,169	252,169	252,169	252,169	252,169	155,181
Moitoring System	(8,000)	Sep-20	Sep-21	0	0	0	0	0	(8,000)	(8,000)	(8,000)	(8,000)	(8,000)	(8,000)	(8,000)	(8,000)	(4,923)
Arcadia Pines	30,938	Nov-20	Sep-21	0	0	0	0	0	30,938	30,938	30,938	30,938	30,938	30,938	30,938	30,938	19,039
Carriage Park	62,318	Nov-20	Sep-21	0	0	0	0	0	62,318	62,318	62,318	62,318	62,318	62,318	62,318	62,318	38,350
Marshall Ridge	44,516	Nov-20	Sep-21	0	0	0	0	0	44,516	44,516	44,516	44,516	44,516	44,516	44,516	44,516	27,395
Randview	178,424	Nov-20	Sep-21	0	0	0	0	0	178,424	178,424	178,424	178,424	178,424	178,424	178,424	178,424	109,799
Delaplain	857,793	Feb-21	Apr-22	0	0	0	0	0	0	0	0	0	0	0	0	857,793	65,984
Herrington Haven	160,450	Feb-21	Apr-22	0	0	0	0	0	0	0	0	0	0	0	0	160,450	12,342
SpringCrest	70,814	Feb-21	Apr-22	0	0	0	0	0	0	0	0	0	0	0	0	70,814	5,447
Woodland Acres	347,862	Mar-21	Apr-22	0	0	0	0	0	0	0	0	0	0	0	0	347,862	26,759
Totals	$ 3,583,650			$ 256,388	$ 256,388	$ 256,388	$ 256,388	$ 256,388	$ 2,146,731	$ 2,146,731	$ 2,146,731	$ 2,146,731	$ 2,146,731	$ 2,146,731	$ 2,146,731	$ 3,583,650	1,530,210
Add: 2019 Constructions																	300,000
Less:																	
Randview																	(65,984)
Delaplain - Wastewater																	(12,342)
Herrington Haven - Wastewater																	(5,447)
SpringCrest - Wastewater																	(26,759)
Commission's 13-Month Average UPIS																	1,719,678
Less: BGW 13-Month Average UPIS																	(8,438,874)
UPIS Adjustment																	$ (6,719,196)

13-Month Average CWIP - Sewer

	Estimated Project Start Date	Estimated Project End Date	Total Estimated Project Budget	Forecasted Year Construction	Base Year Construction	Suspension Construction	Beginning Forecasted Construction	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	13-Month Average
Airview	Sep-20	Sep-21	$ 325,436	$ 64,351	$ 198,305	$ 62,781	$ 261,086	$ 273,956	$ 286,826	$ 299,696	$ 312,566	$ 325,436	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0	$ 115,268
Moitoring System	Sep-20	Sep-21			(10,000)	0	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	0	$ (3,846)
Brocklyn	Sep-20	Dec-21					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Moitoring System	Sep-20	Dec-21																			
Fox Run	Sep-20	Sep-21	232,660	23,511	186,210	22,938	209,148	213,850	218,552	223,254	227,956	232,658	0	0	0	0	0	0	0	0	85,867
Moitoring System	Sep-20	Sep-21			(22,000)	22,938	938	938	938	938	938	938	0	0	0	0	0	0	0	0	361
Kingswood	Sep-20	Sep-21	101,764	6,482	88,959	6,324	95,282	96,578	97,874	99,170	100,466	101,762	0	0	0	0	0	0	0	0	38,142
Moitoring System	Sep-20	Sep-21			(11,000)	22,938	11,938	11,938	11,938	11,938	11,938	11,938	0	0	0	0	0	0	0	0	4,592
Lake Columbia	Sep-20	Sep-21	216,005	42,688	131,670	41,647	173,317	181,855	190,393	198,931	207,469	216,007	0	0	0	0	0	0	0	0	76,512
Moitoring System	Sep-20	Sep-21			(10,000)	22,938	12,938	12,938	12,938	12,938	12,938	12,938	0	0	0	0	0	0	0	0	4,976
Canceled Projects	Sep-20	Sep-21			(85,000)	22,938	(62,062)	(62,062)	(62,062)	(62,062)	(62,062)	(62,062)	0	0	0	0	0	0	0	0	(23,870)
LH Treatment	Sep-20	Sep-21	115,581	0	111,993	3,588	115,581	115,581	115,581	115,581	115,581	115,581	0	0	0	0	0	0	0	0	44,454
Moitoring System	Sep-20	Sep-21			(7,500)	22,938	15,438	15,438	15,438	15,438	15,438	15,438	0	0	0	0	0	0	0	0	5,938
Golden Acres	Sep-20	Sep-21	145,828	39,268	68,250	38,310	106,560	114,414	122,268	130,122	137,976	145,830	0	0	0	0	0	0	0	0	50,047
Moitoring System	Sep-20	Sep-21			(15,000)	22,938	7,938	7,938	7,938	7,938	7,938	7,938	0	0	0	0	0	0	0	0	3,053
Great Oaks	Sep-20	Sep-21	95,518	35,043	26,286	34,189	60,474	67,483	74,492	81,501	88,510	95,519	0	0	0	0	0	0	0	0	31,347
Moitoring System	Sep-20	Sep-21			(10,000)	22,938	12,938	12,938	12,938	12,938	12,938	12,938	0	0	0	0	0	0	0	0	4,976
River Bluffs	May-20	Sep-21	456,151	10,994	434,432	10,726	445,158	447,357	449,556	451,755	453,954	456,153	0	0	0	0	0	0	0	0	173,752
Over Budget		Sep-21			(305,632)	22,938	(282,694)	(282,694)	(282,694)	(282,694)	(282,694)	(282,694)	0	0	0	0	0	0	0	0	(108,728)
Moitoring System		Sep-21			(18,000)	22,938	4,938	4,938	4,938	4,938	4,938	4,938	0	0	0	0	0	0	0	0	1,899
Persimmon Ridge		Sep-21			175,167	22,938	198,105	198,105	198,105	198,105	198,105	198,105	0	0	0	0	0	0	0	0	76,194
Moitoring System		Sep-21			(40,000)	22,938	(17,062)	(17,062)	(17,062)	(17,062)	(17,062)	(17,062)	0	0	0	0	0	0	0	0	(6,562)
Timberland	Sep-20	Sep-21	252,169	80,989	92,165	79,014	171,179	187,377	203,575	219,773	235,971	252,169	0	0	0	0	0	0	0	0	84,528
Moitoring System	Sep-20	Sep-21			(8,000)	22,938	14,938	14,938	14,938	14,938	14,938	14,938	0	0	0	0	0	0	0	0	5,745
Arcadia Pines	Nov-20	Sep-21	30,938	15,660	0	15,278	15,278	18,410	21,542	24,674	27,806	30,938	0	0	0	0	0	0	0	0	9,490
Carriage Park	Nov-20	Sep-21	62,318	31,495	97	30,727	30,824	37,123	43,422	49,721	56,020	62,319	0	0	0	0	0	0	0	0	19,123
Marshall Ridge	Nov-20	Sep-21	44,516	22,484	97	21,935	22,032	26,529	31,026	35,523	40,020	44,517	0	0	0	0	0	0	0	0	13,663
Randview	Nov-20	Sep-21	178,424	89,841	933	87,650	88,583	106,551	124,519	142,487	160,455	178,423	0	0	0	0	0	0	0	0	54,803
Delaplain	Feb-21	Apr-22	857,793	707,047	22,000	128,746	150,746	209,667	268,588	327,509	386,430	445,351	504,272	563,193	622,114	681,035	739,956	798,877	857,798	0	492,676
Herrington Haven	Feb-21	Apr-22	160,450	135,734	0	24,716	24,716	36,027	47,338	58,649	69,960	81,271	92,582	103,893	115,204	126,515	137,826	149,137	160,448	0	90,681
SpringCrest	Feb-21	Apr-22	70,814	59,906	0	10,908	10,908	15,900	20,892	25,884	30,876	35,868	40,860	45,852	50,844	55,836	60,828	65,820	70,812	0	40,021
Woodland Acres	Mar-21	Apr-22	347,862	319,270	0	28,591	28,591	55,197	81,803	108,409	135,015	161,621	188,227	214,833	241,439	268,045	294,651	321,257	347,863	0	186,028
			$ 3,694,227	$ 1,684,763	$ 994,433	$ 923,323	$ 1,917,755	$ 2,112,147	$ 2,306,539	$ 2,500,931	$ 2,695,323	$ 2,889,715	$ 825,941	$ 927,771	$ 1,029,601	$ 1,131,431	$ 1,233,261	$ 1,335,091	$ 1,436,921	$ -	1,571,130
Less:																					
Randview																					(492,676)
Delaplain - Wastewater																					(90,681)
Herrington Haven - Wastewater																					(40,021)
SpringCrest - Wastewater																					(186,028)
Commission 13-Month Average CWIP																					761,724
Less: BGW 13-Month Average CWIP																					(877,758)
CWIP Adjustment																					$ (116,034)

Appendix A
Case No. 2020-00290

13-Month Average UPIS - Water

System	Total Estimated Project Budget	Estimated Project Start Date	Estimated Project End Date	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	13-Month Average
Center Ridge WD01 - Water	$ 152,910	Jun-20	Sep-21	$ -	$ -	$ -	$ -	$ -	$ 152,910	$ 152,910	$ 152,910	$ 152,910	$ 152,910	$ 152,910	$ 152,910	$ 152,910	$ 94,098
Center Ridge WD02 - Water	$ 203,999	Jun-20	Sep-21	0	0	0	0	0	203,999	203,999	203,999	203,999	203,999	203,999	203,999	203,999	125,538
Center Ridge WD03 - Water	$ 243,354	Jun-20	Sep-21	0	0	0	0	0	243,354	243,354	243,354	243,354	243,354	243,354	243,354	243,354	149,756
Center Ridge WD04 - Water	$ 137,046	Jun-20	Sep-21	0	0	0	0	0	137,046	137,046	137,046	137,046	137,046	137,046	137,046	137,046	84,336
Monitoring	$ (40,000)	Jun-20	Sep-21						(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(24,615)
Eliminated Projects	$ (15,000)	Jun-20	Sep-21						(15,000)	(15,000)	(15,000)	(15,000)	(15,000)	(15,000)	(15,000)	(15,000)	(9,231)
Totals				$ -	$ -	$ -	$ -	$ -	$ 682,310	$ 682,310	$ 682,310	$ 682,310	$ 682,310	$ 682,310	$ 682,310	$ 682,310	419,882
Less: BGW 13-Month Average UPIS																	(1,188,537)
UPIS Adjustment																	$ (768,655)

13-Month Average CWIP - Water

	Estimated Project Start Date	Estimated Project End Date	Total Estimated Project Budget	Forecasted Year Construction	Base Year Construction	Suspension Construction	Beginning Forecasted Construction	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	13-Month Average
Center Ridge WD01 - Water	Jun-20	Sep-21	$ 152,910	$ 46,307	$ 61,426	$ 45,177	$ 106,603	$ 115,864	$ 125,125	$ 134,386	$ 143,647	$ 152,908	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 51,687
Center Ridge WD02 - Water	Jun-20	Sep-21	203,999	51,629	102,000	50,370	152,370	162,696	173,022	183,348	193,674	204,000	0	0	0	0	0	0	0	0	70,518
Center Ridge WD03 - Water	Jun-20	Sep-21	243,354	101,333	43,159	98,862	142,021	162,288	182,555	202,822	223,089	243,356	0	0	0	0	0	0	0	0	78,008
Center Ridge WD04 - Water	Jun-20	Sep-21	137,046	45,766	46,631	44,650	91,281	100,434	109,587	118,740	127,893	137,046	0	0	0	0	0	0	0	0	45,669
		Sep-21		(40,000)			(40,000)	(48,000)	(56,000)	(64,000)	(72,000)	(80,000)	0	0	0	0	0	0	0	0	(24,615)
		Sep-21		(15,000)			(15,000)	(18,000)	(21,000)	(24,000)	(27,000)	(30,000)	0	0	0	0	0	0	0	0	(9,231)
Totals			$ 737,310	$ 190,035	$ 253,216	$ 239,058	$ 437,275	$ 475,282	$ 513,289	$ 551,296	$ 589,303	$ 627,310	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Commission's 13-Month Average CWIP																					212,036
Less: BGW 13-Month Average CWIP																					(97,909)
CWIP Adjustment																					$ 114,127

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2020-00290 DATED AUG 02 2021

Water Rates

Center Ridge Water System		
Flat Rate	$77.63	Per Month
Nonrecurring Charges		
Tap Fee	$350.00	
Connection	0.00	
Reconnection	0.00	
Late Payment Penalty	0.00	
Returned Check Charge	0.00	

Sewer Rates

All Systems except Delaplain, Herrington Haven, Springcrest, and Woodland Acres		
Residential	$85.97	Per Month per unit
Multi-Family	64.48	Per Month per unit
Non-residential/Commercial	214.93	Per Month per unit
Residential Equivalent 12,000 gallons		
Nonrecurring Charges		
Airview Estates		
Tap On Fee	$0.00	
Late Payment Penalty	0.00	
Returned Check Fee	0.00	
Termination of Service Charge	0.00	
Reconnection of Service Charge	0.00	
Arcadia Pines		
Late Payment Penalty	$0.00	
Tap On Fee	500.00	
Brocklyn Subdivision		
Tap On Fee	$0.00	
Late Payment Penalty	0.00	
Returned Check Fee	0.00	

Termination of Service Charge	0.00
Reconnection of Service Charge	0.00
Carriage Park	
Late Payment Penalty	$0.00
Tap On Fee	0.00
Fox Run Estates	
Tap On Fee	$0.00
Late Payment Penalty	0.00
Returned Check Fee	0.00
Termination of Service Charge	0.00
Reconnection of Service Charge	0.00
Kingswood Development	
Tap On Fee	$0.00
Lake Columbia Estates	
Late Payment Penalty	$0.00
Tap On Fee	$0.00
Longview and Homestead Subdivisions	
Tap On Fee	$0.00
Marshall Ridge	
Late Payment Penalty	$0.00
Tap On Fee	500.00
Great Oaks Subdivision	
Late Payment Penalty	$0.00
Returned Check Fee	0.00
Field Collection Charge	0.00
Tap On Fee	750.00
Reconnection Fee	0.00
Golden Acres Subdivision	
Late Payment Penalty	$0.00
Returned Check Fee	0.00
Field Collection Charge	0.00

Tap On Fee	250.00
Reconnection Fee	0.00
Persimmon Ridge Subdivision	
Late Penalty Payment	0.00
Tap On Fee	0.00
Randview	
Late Payment Penalty	$0.00
Connection Fee	0.00
Reconnection Fee	0.00
Duplex	
Connection Fee	0.00
Reconnection Fee	0.00
Tap On Fee	0.00
City of River Bluffs & Environs	
Late Payment Penalty	$0.00
Tap On Fee	0.00
Timberland Subdivision	
Late Payment Penalty	$0.00
Tap On Fee	0.00

APPENDIX C

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2020-00290 DATED AUG 02 2021

	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21
Bluegrass Water Connections	3,408	3,408	3,408	3,408	3,408	3,408	3,408	3,408	3,408	3,408	3,408	3,408	3,408
Total CSWR Connections	52,605	52,605	59,605	59,605	59,605	69,805	69,805	69,805	85,000	85,000	85,000	85,000	85,000
Monthly Allocation Percentage	6.48%	6.48%	5.72%	5.72%	5.72%	4.88%	4.88%	4.88%	4.01%	4.01%	4.01%	4.01%	4.01%
										13-Month Average Allocation Percentage			4.98%

Base Connections	52,605	52,605	59,605	59,605	59,605	69,805	69,805	69,805	85,000	85,000	85,000	85,000	85,000
Continual Additional Connections	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000	35,000
Total Connections	87,605	87,605	94,605	94,605	94,605	104,805	104,805	104,805	120,000	120,000	120,000	120,000	120,000
Percentage of Connections Attributed to BD per Month	39.95%	39.95%	37.00%	37.00%	37.00%	33.40%	33.40%	33.40%	29.17%	29.17%	29.17%	29.17%	29.17%
											13 Month Average		33.61%

APPENDIX D

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2020-00290 DATED AUG 02 2021

CSWR, LLC General & Administrative Budget						
Admin & Human Resources	$	6,320,268	(236,282)			Adjusment to Forecast Number
			(691,141)			Removal of Unfilled Vacant Position Compensation
			(139,338)			Adjustment to Health Insurance
			(21,248)			Adjustment to Dental Insurance
			(177,289)			Allowance for 3% salary raise from the end of base period
			(102,000)			Removal of Executive Auto Allowance
			(8,864)		4,944,106	Adjustment to 401(k) Matching
Office Supplies		106,271			106,271	
Management Consulting		243,300	(243,300)		-	Failure to Meet Burden
Engineering Consulting		20,400			20,400	
Auditor & Accounting Services		133,000			133,000	
Legal Fees		87,684			87,684	
IT		238,250			238,250	
Rent		168,000			168,000	
Insurance		77,000			77,000	
Miscellaneous		6,000			6,000	
Total Corporate SG&A	**$**	**7,400,173**		**$**	**5,780,711**	

Total Adjusted Corporate SG&A	$	5,780,711
Multiply By: BD Percentage		33.61%
Allocated BD		1,942,814
Total Adjusted Corporate SG&A		5,780,711
Subtract: Allocated BD		1,942,814
Allocatable Corporate SG&A	$	3,837,897
Multiply by: Overhead Allocation Percentage		4.98%
Bluegrass Water Allocated Overhead	$	191,127
KY Specific Travel Expense	$	11,392
Bluegrass Water Overhead	$	202,519

	Bluegrass Customers	Percent of Total Customers	Annual OHA	
Sewer	2,321	87.35%	$	176,909
Water	336	12.65%	$	25,610
Total	2,657			

APPENDIX E

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2020-00290 DATED AUG 02 2021

Detailed Income Statement - Sewer

Description	Bluegrass Water's Forecasted Test Year	Commission Adjustments	System Removal	Commission Forecasted Test Year	Revenue Increase	Commission Test-Year at New Rates
Operating Revenues						
Revenues - Sewer Service	$ 1,154,988	$ -	$ (246,822)	$ 908,166	$ 959,583	$ 1,867,749
Operating Expenses						
Operation and Maintenance						
Sewer - Contract Operations	1,029,348	0	(219,973)	809,375	0	809,375
Sewer - Other Operations	310,377	0	(66,328)	244,049	0	244,049
Sewer - Maintenance	112,008	0	(23,936)	88,072	0	88,072
Customer Billing Expense	75,237	0	(16,078)	59,159	0	59,159
Uncollectible Accounts	8,662	0	(1,851)	6,811	7,197	14,008
Allocated Overhead	292,902	(115,993)	(37,806)	139,103	0	139,103
Administrative Servcies	41,122	(35,450)	(1,212)	4,460	0	4,460
Property Insurance	172,604	0	(36,886)	135,718	0	135,718
Regulatory Expense	6,322	0	(1,351)	4,971	0	4,971
PSC Assessment	841	975	0	1,816	1,919	3,735
Total Operation and Maint. Exp.	2,049,424	(150,468)	(405,421)	1,493,535	9,116	1,502,651
Other Expenses						
Depreciation - Net of CIAC Amort	264,095	(214,398)	0	49,697	0	49,697
State Income Tax	0	(28,544)	0	(28,544)	47,523	18,979
Federal Income Tax	0	(113,889)	0	(113,889)	189,618	75,729
General Taxes	17,622	0	(3,766)	13,856	0	13,856
Total Other Expense	281,716	(356,831)	(3,766)	(78,880)	237,141	158,261
Total Operating Expenses	2,331,141	(507,299)	(409,187)	1,414,654	246,257	1,660,911
Net Utility Operating Income	$ (1,176,153)	$ 507,299	$ 162,365	$ (506,488)	$ 713,326	$ 206,838

APPENDIX F

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2020-00290 DATED AUG 02 2021

Detailed Income Statement - Water

Description	Bluegrass Water's Forecasted Test Year	Commission Adjustments	Commission Forecasted Test Year	Revenue Increase	Commission Test-Year at New Rates
Operating Revenues					
Revenues - Water Sales	$ 90,000	$ -	$ 90,000	$ 223,001	$ 313,001
Operating Expenses					
Operation and Maintenance:					
Water - Contract Operations	144,048	0	144,048	0	144,048
Water - Other Operations	30,000	0	30,000	0	30,000
Water - Maintenance	7,488	0	7,488	0	7,488
Customer Billing Expense	10,823	0	10,823	0	10,823
Uncollectible Accounts	675	0	675	1,673	2,348
Allocated Overhead	43,059	(17,449)	25,610	0	25,610
Administrative Servcies	7,109	(6,176)	933	0	933
Property Insurance	10,812	0	10,812	0	10,812
Regulatory Expense	0	180	180	446	626
Total Operating and Maint. Exp.	254,014	(23,445)	230,569	2,119	232,688
Other Expenses					
Depreciation - Net of CIAC Amort	31,941	(20,274)	11,667	0	11,667
State Tax					
State Income Tax	0	(6,275)	(6,275)	11,044	4,769
Current Federal Income Tax	0	(25,037)	(25,037)	44,066	19,029
General Taxes	92	0	92	0	92
Total Other Expense	32,033	(51,586)	(19,553)	55,110	35,557
Total Operating Expenses	286,047	(75,031)	211,016	57,229	268,245
Utility Operating Income	$ (196,047)	$ 75,031	$ (121,016)	$ 165,772	$ 44,756

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ORIGINAL ARTICLE

New approach to estimating the cost of common equity capital for public utilities

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Abstract The regulatory process for setting public utilities' allowed rate of return on common equity has generally used the Gordon DCF, CAPM and Risk Premium specifications to estimate the cost of common equity. Despite the widely known problems with these models, there has been little movement to adopt more recently developed asset pricing models to provide additional evidence for estimating the cost of capital. This paper presents, validates empirically and applies a general yet simple consumption-based asset pricing specification to model the risk-return relationship for stocks and estimate the cost of common equity for public utilities. The model is not necessarily superior to other models in its practical results, yet these results do indicate that it should be used to provide additional estimates of the cost of common equity. Additionally, the model raises doubts as to whether assets such as utility stocks are a consumption (business cycle) hedge.

Keywords Public utilities · Cost of capital · GARCH · Consumption asset pricing model

JEL Classification G12 · L94 · L95

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1 Introduction

Following electricity deregulation with the National Energy Policy Act of 1992, the estimation of the cost of common equity capital remains a critical component of the utility rate-of-return regulatory process. Since the cost of common equity is not observable in capital markets, it must be inferred from asset pricing models. The models that are commonly applied in regulatory proceedings are the Gordon (1974) Discounted Cash Flow (DCF), the Capital Asset Pricing (CAPM) and Risk Premium Models. There are other tools used to estimate the cost of common equity such as comparable earnings or earnings-to-price ratios, but they are not asset pricing models. The empirical literature on the CAPM is vast {Fama and French (2004)} and the CAPM is used by a number of US regulatory jurisdictions. The DCF model has not been empirically tested to the same extent as the CAPM, yet it is considered by many US regulatory jurisdictions.

The purpose of this paper is to present, test empirically and apply a recently developed general consumption-based asset pricing model that estimates the risk-return relationship directly from asset pricing data and, when estimated with recently developed time series methods, produces a prediction of the equity risk premium that is driven by its predicted volatility. The predicted risk premium is then added to a risk-free rate of return to provide an estimate of the cost of common equity. We predict two forms of the equity risk premium with the model, the risk premium net of the risk-free rate and the equity-to-debt risk premium (equity risk premium net of the relevant bond yield for the company's stock). Either can be applied to predict the common equity cost of capital for a public utility. Although the model is tested and applied to public utilities for rate of return regulation, it can be used to estimate the cost of capital for any stock. Section 2 reviews the asset pricing models typically used in public utility rate cases and the generalized consumption asset pricing model we propose to estimate the cost of common equity. Section 3 discusses the data and the empirical testing of the consumption asset pricing model. Section 4 reviews the application of the model and compares it with the DCF and CAPM results. Section 5 is the conclusion.

2 DCF, CAPM and consumption asset pricing model

2.1 DCF and CAPM approaches

The standard DCF model frequently used in estimative the cost rate of common equity in regulatory proceedings is defined by the following equation:

$$k = D_0 (1 + g) / P_0 + g,$$

where k is the expected return on common equity; D_0 is the current dividend per share; g is the expected dividend per share growth rate; and P_0 is the current market price.

The DCF was developed by Gordon (1974) specifically for regulatory purposes. Underlying the DCF model is the theory that the present value of an expected future stream of net cash flows during the investment holding period can be determined by discounting those cash flows at the cost of capital, or the investors' capitalization rate. DCF theory indicates that an investor buys a stock for an expected total return rate which is derived from cash flows received in the form of dividends plus appreciation in market price (the expected growth rate) over the investment holding period. Mathematically, the expected dividend yield ($D_0(1+g)/P_0$) on market price plus an expected growth rate equals the capitalization rate, i.e., the expected return on common equity.

The standard DCF contains several restrictive assumptions, the most contentious of which during utility cost of capital proceedings is typically that dividends per share (DPS), book value per share (BVPS), earnings per share (EPS) as well as market price grow at the same rate in perpetuity. There is also considerable contention over the proper proxy for g, prospective or historical growth in DPS, BVPS, EPS and market price and over what time period. In addition, although the standard DCF described above is a single stage annual growth model, there is considerable discussion over the use of multiple stage growth models during regulatory proceedings. Some analysts use the discrete version and others use the continuous version of the DCF model. Solving these models for k, the cost of common equity, results in differing equations to solve for k. The equation above is from the discrete version. The continuous version uses the current dividend yield and is not adjusted by g, which results in a lower estimate for k. Because of these and other restrictive assumptions that require numerous subjective judgments in application, it is often difficult for regulatory commissions to reconcile the frequently large disparities in rates of return on common equity recommended by various parties in a public utility rate case.

The CAPM model is defined by the following equation:

$$k = R_f + \beta\left(R_m - R_f\right),$$

where k is the expected return on common equity; R_f is the expected risk-free rate of return; β is the expected beta; and R_m is the expected market return.

CAPM theory defines risk as the co-variability of a security's returns with the market's returns or β, also known as systematic or market risk, with the market beta being defined as 1.0. Because CAPM theory assumes that all investors hold perfectly diversified portfolios, they are presumed to be exposed only to systematic risk and the market (according to the model) will not reward them a risk premium for unsystematic or non-market risk. In other words, the CAPM presumes that investors require compensation only for systematic or market risks which are due to macroeconomic and other events that affect the returns on all assets. Mathematically, the CAPM is applied by adding a forward-looking risk-free rate of return to an expected market equity risk premium adjusted proportionately by the expected beta to reflect the systematic risk.

As with the DCF, there is considerable contention during regulatory cost of capital proceedings as to the proper proxies for all components of the CAPM: the R_f, the R_m, as well as β. In addition, the CAPM assumption that the market will only reward investors for systematic or market risk is extremely restrictive when estimating the expected return on common equity for a single asset such as a single jurisdictional regulated operating utility. Additionally, this assumption requires that the investor have a perfectly diversified portfolio, that is, one with no unsystematic risk. Since this assumption is not applicable, estimating the cost of common equity capital for a single utility's common equity undoubtedly will not reflect the risk actually faced by the imperfectly diversified investor.

As will be discussed in the next section, our application of the risk premium approach, the consumption asset pricing model and GARCH[1] rest on minimal assumptions and restrictions and therefore requires considerably less judgment in its application.

2.2 Risk premium approach, consumption asset pricing models, and GARCH

A widely used model to estimate the cost of common equity capital for public utilities is the risk premium approach. This approach often estimates the expected rate of return as the long-term historic mean of the realized risk premium above an historic yield plus the current yield of the relevant bond applicable to a specific utility or peer group of utilities. Litigants in public utility rate proceedings debate the choice of inputs to estimate the risk premium as well as how far back to reach into history to collect data for calculating an average that is representative of a forward-looking premium.

It is surprising that, as popular as the risk premium method is in public utility rate cases, the intuitively appealing general consumption-based asset pricing model, with its minimal assumptions and strong theoretical foundation, has not been applied to estimate the cost of common equity capital for public utilities. The model provides projections of the conditional expected risk premium on an asset based on its relation to its predicted conditional volatility. This model generalizes the well known special case asset pricing models such as the Merton (1973) intertemporal capital asset pricing model, Campbell (1993) intertemporal asset pricing model, and the habit-persistence model of Campbell and Cochrane (1999), which are special cases of the general model. The relation of the model to their specialized cases can be found in Cochrane (2006) and Cochrane (2007). The approach of consumption asset pricing models is to make investment decisions that maximize investors' utility from the consumption that they ultimately desire, not returns.

Even if the model is not used to project directly the expected risk premium, it can, at a minimum, be used to verify that the risk premia data chosen for estimating the cost of capital is empirically validated by fitting the model well. The model can be used to predict the equity risk premia net of the risk-free rate (equity risk premium) or to predict the equity-to-debt risk premium for a firm. We perform both of these empirical tests in this paper. The general consumption-based asset pricing model developed in Michelfelder and Pilotte (2011) and based on Cochrane (2004) provides the relationship of the ex ante risk premium to an asset's own volatility in return:

$$E_t[R_{i,t+1}] - R_{f,t} = -\frac{vol_t[M_{t+1}]}{E_t\left[M_{t+1}\right]} vol_t[R_{i,t+1}] corr_t[M_{t+1}, R_{i,t+1}]. \tag{1}$$

[1] GARCH refers to the generalized autoregressive conditional heteroskedasticity regression model which is discussed below.

where vol_t is the conditional volatility, $corr_t$ is the conditional correlation, and M_{t+1} is the stochastic discount factor (SDF).

The SDF is the intertemporal marginal rate of substitution in consumption, or, $M_{t+1} = \beta \frac{U_{c,t+1}}{U_{c,t}}$, where the U_c's are the marginal utilities of consumption in the next period, $t+1$, and the current period, t, and β is the discount factor for period t to $t+1$. Equation 1 shows that the algebraic sign of the relation between the expected risk premium and the conditional volatility of an asset's risk premium is determined by the correlation between the asset's return and the SDF. That is, the direction of the relation between the asset return and the ratio of intertemporal marginal utilities in consumption inversely determines the relation between the expected risk premium and conditional volatility. When the correlation is equal to negative one, the asset's conditional expected risk premium is perfectly positively correlated with its conditional volatility. A positive relation between the conditionally expected risk premium and volatility obtains when $-1 < corr_t < 0$. A negative relation obtains when $0 < corr_t < 1$. For an asset that represents a perfect hedge against shocks to the marginal utility of consumption, with $corr_t = 1$, there will be a perfect negative correlation between the conditionally expected risk premium and its volatility.[2] Therefore, estimates of the relation between the first two conditional moments of a public utility stock's returns provide a direct test of the effectiveness of a public utility stock, or any asset, as a consumption hedging asset. In Eq. 1, $vol_t[M_{t+1}]/E_t[M_{t+1}]$ is the slope of the mean-variance frontier. If this slope changes over time, the estimated relation between the stock's risk and return will vary over time. This model can also be viewed simplistically as the projected expected risk premium as a function of its own projected risk, given information available at time t.

Note that the model allows for the expected risk premium to be negative if the asset hedges shocks to the marginal utility of consumption. Investors are willing to accept an expected rate of return lower than the risk-free rate of return if the pattern of volatility is such that returns are expected to rise with expected reductions in consumption. Simply, investors are willing to *pay* a premium for a higher level of returns volatility that has the desired pattern of returns. These desired returns patterns have a tendency to offset drops in consumption. Therefore, this model shows that investors may not be averse to volatility, but rather to the timing of expected changes in returns.

Summarizing, several conclusions can be drawn from the general model of asset pricing. First, the sign of the relation between a stock's risk premium and conditional volatility depends on the extent to which the stock serves as an intertemporal hedge against shocks to the marginal utility of consumption. Second, the relation between stock risk and return may be time-varying depending on changes in the slope of the mean-variance frontier. Third, hedging assets have desired patterns of volatility that result in expected rates of return that are less than the risk-free rate. We do not expect

[2] A hedging asset is one that has a positive increase in returns that is coincident with a positive shock in the ratio of intertemporal marginal utilities of consumption. Note that if we assume a concave utility function in consumption, as consumption declines, the marginal utility of consumption rises relative to last period marginal utility. If we think of a decline in consumption as a contraction in the business cycle, the hedging asset delivers positive changes in returns when the business cycle is moving into a contraction, and therefore the asset is a business cycle hedge.

that public utility stocks serve as a hedging asset as they are not viewed as defensive stocks (they do not rise in value during downturns in the stock market) due to asymmetric regulation and returns as discussed in detail in Kolbe and Tye (1990). Under asymmetric regulation, utility regulators have a tendency to allow the return on equity to fall below the allowed return during downturns in the business cycle and to reduce the return should it rise above the allowed return during expansions. Therefore we expect that the parameter estimates of the return-risk relationship to be positive as utility stocks are hypothesized to not be hedges.

We use the GARCH model to estimate the general asset pricing model since the GARCH model accommodates ARCH effects that improve the efficiency of the parameter estimates. It also provides a volatility forecasting model for the conditional volatility of the asset's risk premium. The conditional volatility projection is used, in turn to predict the expected risk premium. We also use the GARCH-in-Mean model (GARCH-M) since it specifies that the conditional expected risk premium is a linear function of its conditional volatility. There is a vast body of literature that estimates asset pricing models with the GARCH and GARCH-M methods and therefore we will not attempt to summarize them here.

The GARCH-M model was initially developed and tested by Engle et al. (1987) to estimate the relationship between US Treasury and corporate bond risk premia and their expected volatilities. The GARCH-M model is specified as:

$$R_{t+1} - R_{f,t+1} = \alpha\sigma_{t+1}^2 + \varepsilon_{t+1} \tag{2}$$

$$\sigma_{t+1}^2 = \beta_0 + \beta_1\sigma_t^2 + \beta_2\varepsilon_t^2 + \eta_{t+1} \tag{3}$$

$$\varepsilon_t \,|\psi_{t-1} \sim T(0, \sigma_t^2) \tag{4}$$

where R_{t+1} is the expected total return on the public utility stock index or individual utility stock; $R_{f,t+1}$ is the risk-free rate of return or the yield on an index of public utility bonds of a specified bond rating for the equity-to-debt premium; σ_{t+1}^2 is the conditional or predicted variance of the risk premium that is conditioned on past information (ψ_{t-1}); and ε_t is the error term that is conditional on ψ_{t-1}.

The conditional distribution of the error term is specified as the non-unitary variance T-distribution due to the thick-tailed distribution of the risk premia data. If the error distribution is thick-tailed, using an approximating distribution that accommodates thick tails improves the efficiency of the estimates. The parameter, α, is the return-to-risk coefficient as specified in Eq. 1 as:

$$\alpha = -\frac{vol_t[M_{t+1}]}{E_t\left[M_{t+1}\right]} corr_t[M_{t+1}, R_{i,t+1}] \tag{5}$$

Note that the coefficient will be positive if the conditional correlation between the SDF and the asset return is negative, indicating that the stock is not a hedging asset. Recall that the SDF is the ratio of intertemporal marginal utilities. Assuming a concave utility function, an upward shock in the ratio implies falling consumption, therefore an associated rise (positive correlation) in the return (R_i) would offset the reduction in consumption, thereby causing the sign of α to be negative. The parameter, α, is also the ratio of risk premium to variance, or, the Sharpe ratio.

The intercept in Eq. 2 is restricted to zero as specified by the general asset pricing model specification. The restriction on the intercept equal to zero has been found to be robust in producing consistently positive and significant relationships between equity risk premia and risk in GARCH-M models. This is discussed in Lanne and Saikkonen (2006) and Lanne and Luoto (2007). We have found the same results in our modeling in this paper, although we have excluded these results for brevity (available upon request). Therefore we specify the prior assumption that the intercept or the "excess" return, i.e., the return not associated with risk to be equal to zero and drop the intercept from the model.

The consumption asset pricing model is estimated in the empirical section of the paper and applied in the applications section of the paper. The model is tested to (1) determine if equity-to-debt risk premium indices for utilities of differing risk specified by differing bond ratings are validated by the asset pricing model and therefore have some empirical support for risk premium prediction and application to utility cost of capital estimation, (2) determine whether equity risk premia can be predicted and fit the model and therefore be used to estimate the cost of common equity, (3) empirically test the consumption asset pricing model, and (4) ascertain whether utility stocks are assets that hedge shocks to the marginal utility of consumption.

If utility stocks are hedging assets then the cost of common equity should reflect a downward adjustment to a specified risk-free rate to reflect investors' preferences for a hedge and the compensation that they are willing to pay for it.

3 Data and empirical results

We use portfolios as represented by public utility stock and bond indices to estimate the conditional return-risk relationship for the equity-to-debt premium. The equity-to-debt risk premium data employed for estimating Eq. 1 with the GARCH-M conditional return-risk regressions are monthly total returns on the Standard and Poor's Public Utilities Stock Index (utility portfolio), and the monthly Moody's Public Utility Aa, A, and Baa yields for the debt cost. We also obtained equity risk premia for the utility portfolio using the Fama-French specified risk-free rate of return, which is the holding period return on a 1-month US Treasury Bill. The data range from January 1928 to December 2007 with 960 observations. The return-risk relationships for the equity-to-debt premia are risk-differentiated by their own bond rating.

As a check, we also estimate Eq. 1 with the GARCH-M for large common stock returns using the monthly Ibbotson Large Company Common Stocks Portfolio total returns and the Ibbotson US Long-Term Government income returns as the risk-free rate. Additionally, as another check, we do the same for the University of Chicago's Center for Research in Security Prices value-weighted stock index (CRSP) using the Fama-French risk-free rate. This is the Fama-French specification of the market equity risk premium. The data range from January 1926 to December 2007 with 984 observations for the Large Company Common Stock estimation and the data ranges

Table 1 Descriptive statistics: public utility and large company common stocks equity-to-debt and equity risk premia

Utility bond rating	Mean	Std. Dev.	Skewness	Kurtosis	JB
Aa	0.0037	0.0568	0.0744	10.07	2,001.2***
A	0.0035	0.0568	0.0632	10.06	1,991.8***
Baa	0.0031	0.0568	0.0375	10.02	1,973.6***
Ibbotson					
Large common stocks	0.0054	0.0554	0.4300	12.84	3,954.7***
CRSP value-weighted stock index	0.0062	0.0544	0.2309	10.92	2,519.1***

The public utility equity-to-debt risk premia monthly time series is from January 1928 to December 2007 with 960 observations. The equity risk premium monthly time series for the Large Common Stocks and the CRSP index are January 1926 to December 2007 with 984 observations, and January 1926 to December 2007 with 984 observations, respectively. The public utility stocks equity-to-debt risk premia are calculated as the total return on the S&P Public Utilities Index of stocks minus the Moody's Public Utility Aa, A, and Baa Indices yields to maturity. The Large Company Common Stock equity risk premia are the monthly total returns on the Ibbotson Large Company Common Stocks Portfolio minus the Ibbotson Long-Term US Government Bonds Portfolio income yield. The CRSP equity risk premia, or the Fama-French market risk premia are the CRSP total returns on the value-weighted equity index minus the 1-month holding period return on a 1 month Treasury Bill. The Jarque-Bera (JB) statistic is a goodness-of-fit measure of the departure of the distribution of a data series from normality, based on the levels of skewness and excess kurtosis. The JB statistic is χ^2 distributed with 2° of freedom. *** Significant at 0.01 level, one-tailed test

from January 1928 to January 2007 with 960 observations (same as the utilities) for the CRSP estimation.

Table 1 displays the descriptive statistics for these data. We have estimated the mean, standard deviation, skewness and kurtosis parameters, as well as the Jarque-Bera (JB) statistic to test the distribution of the data. The means of the utility equity-to-debt risk premia fall as the risk (bond rating) declines. This is consistent with the notion that larger yields are subtracted from stock returns the lower the bond rating. Intertemporally, there is an inverse relationship between risk premia and interest rates (See Brigham et al. (1985) and Harris et al. (2003)). The mean for risk premia will have a tendency to be larger during low interest rate periods.

Not surprisingly, large company common stocks have the highest mean risk premia as the majority of these firms are not rate-of-return regulated firms with a ceiling on their ROE's close to their cost of capital. Interestingly, the standard deviations of the utility stock returns are similar and slightly higher than large company common stocks. Skewness coefficients are small and positive except for Ibbotson large company common stock returns and CRSP returns that have large positive skewness. This suggests that large unregulated stocks have a tendency to have more and larger positive shocks in returns than do utilities that are rate of return regulated. The kurtosis values show that all of the risk premia are thick-tail distributed. This is also found in the significant JB statistics that test the null hypothesis that the data are normally distributed. The null hypothesis is rejected for all assets. The high kurtosis, low skewness, and significant JB statistics show that the risk premia data are substantially thick-tailed, except for non-utility stocks that are both skewed and thick-tailed. Therefore, robust estimation methods are required to produce efficient regression estimates with non-normal data. Additionally, although not shown but available upon request, the serial correlation and

ARCH Lagrange Multiplier tests show that residuals from OLS regressions of risk premia on volatilities follow an ARCH process. Therefore, the GARCH-M method will improve the efficiency of the estimates. We specify the regression error distribution as a non-unitary variance T-distribution so that thick-tails could be accommodated in the estimation and therefore produce increasingly efficient parameter estimates.

We used maximum likelihood estimation with the likelihood function specified with the non-unitary-variance T-distribution as the approximating distribution of the residuals to accommodate the thick-tailed nature of the error distribution. The equations are estimated as a system using the Marquardt iterative optimization algorithm. The chosen software for estimating the model was EViews© version 6.0 (2007).

Table 2 shows the GARCH-M estimations for the consumption asset pricing Eq. 1. We have estimated Eq. 1 for the utility equity risk premia using the Fama-French risk-free rate in addition to the equity-to-debt risk premia risk-differentiated by bond ratings and the two measures of the market equity risk premium. The chosen measure of volatility is the variance of risk premium (in contrast to other such measures such as the standard deviation or the log of variance. Although these results are not shown for brevity, they are robust to these other measures of volatility). The slope, which is the predicted return-to-predicted risk coefficient and Sharpe ratio, is positive and significant at the 99% level for all assets except the utility stock returns with Baa bonds, which is significant at the 95% level. Given that all slopes are positive, public utility stocks are not found to hedge shocks to the marginal utility of consumption. Note that the reward-to-risk slope rises as bond rating rises. This suggests that lower risk utility stocks provide a higher incremental risk-premium for an increase in conditional volatility. This is consistent with other studies that find that lower risk assets, such as shorter maturity bonds, have higher Sharpe Ratios than long-term bonds and stocks. See Pilotte and Sterbenz (2006) and Michelfelder and Pilotte (2011).

The variance equation shows that all GARCH coefficients (β's) are significant at the 1% level and the sums of β_1 and β_2 are close to, but less than 1.0, indicating that the residuals of the risk premium equation follow a GARCH process and that the persistence of a volatility shock on returns and stock prices for utility stocks is temporary. The estimates of the non-unitary variance T-distribution degrees of freedom parameter are low and statistically significant, indicating that the residuals are well approximated by the T. Similar values for the log-likelihood functions (Log-L) show that each of the regressions has a similar goodness-of-fit. Chi-squared distributed likelihood ratio tests (not shown but available upon request) that compare the goodness of fit among the T and normal specifications of the likelihood function of the GARCH-M regressions show that the T has a significantly better fit than the normal distribution.

The GARCH-M results for the large company common stocks portfolio are similar to those of the utility stocks. Not surprisingly, large company common stocks do not hedge shocks to the marginal utility of consumption and volatility shocks temporarily affect their valuations. The exception is that the return-risk slope is substantially higher than utility stock slopes. This is partially due to the risk-free nature of the risk-free rates used with the non-utility equity risk premia compared to the

Table 2 Estimation of return-risk relation: public utility and large company common stocks

Utility bond rating	α	β_0	β_1	β_2	Log-L	T dist. D.F.
Aa	1.5183*** (0.5308)	0.0000** (0.0000)	0.8791*** (0.0230)	0.1031*** (0.0219)	1,604.4	9.9254*** (3.0272)
A	1.4536*** (0.5308)	0.0000** (0.0000)	0.8790*** (0.0230)	0.1033*** (0.0220)	1,605.0	9.9381*** (3.0408)
Baa	1.3318** (0.5303)	0.0000** (0.0000)	0.8789*** (0.0229)	0.1040*** (0.0220)	1,605.2	10.0*** (3.0540)
Fama-French R_f	2.1428*** (0.5318)	0.0000** (0.0000)	0.8811*** (0.0232)	0.0979*** (0.0212)	1,601.0	9.8773*** (2.9700)
Ibbotson						
Large company common stocks	2.7753*** (0.5513)	0.0001*** (0.0000)	0.8381*** (0.0269)	0.1186*** (0.0332)	1,620.8	8.8457*** (2.1613)
CRSP value-weighted stock index	3.3873*** (0.5673)	0.0001*** (0.0000)	0.8330*** (0.0270)	0.1149*** (0.0358)	1,598.9	8.8571*** (1.9505)

The results below are the GARCH-in-Mean regressions for the risk premium ($R_{t+1} - R_{f,t+1}$) on the conditional variance of the risk premium (σ^2_{t+1}) in the mean equation. The intercept in the mean equation is restricted to be equal to zero. The public utility equity-to-debt risk premia monthly time series is from January 1928 to December 2007 with 960 observations. The equity risk premium monthly time series for the Large Company Common Stocks and the CRSP index are January 1926 to December 2007 with 984 observations, and January 1926 to December 2007 with 984 observations, respectively. The public utility stocks equity-to-debt risk premia are calculated as the total return on the S&P Public Utilities Index of stocks minus the Moody's Public Utility Aa, A, and Baa Indices yields to maturity. The Large Company Common Stock equity risk premia are the monthly total returns on the Ibbotson Large Company Common Stocks Portfolio minus the Ibbotson Long-Term US Government Bonds Portfolio income yield. The CRSP equity risk premia, or the Fama-French market risk premia are the CRSP total returns on the value-weighted equity index minus the 1-month holding period return on a 1 month Treasury Bill. The estimated model is:

$$R_{t+1} - R_{f,t+1} = \alpha\sigma^2_{t+1} + \varepsilon_{t+1} \text{ where } \alpha = -\frac{vol_t[M_{t+1}]}{E_t[M_{t+1}]} corr_t[M_{t+1}, R_{i,t+1}]$$

$$\sigma^2_{t+1} = \beta_0 + \beta_1\sigma^2_t + \beta_2\varepsilon^2_t + \eta_{t+1}$$

The conditional distribution of the error term is the non-unitary variance T-distribution to accommodate the kurtosis of the risk premia and error term. Standard errors are in parentheses. ***, **, * denote significance at the 0.01, 0.05, and 0.10 levels, respectively for two-tail tests

utility bond yields that reflect risk. The utility stocks slope value of 2.1428 using the Fama-French risk-free rate is closer to the higher CRSP value of 3.3873 that is also based on the Fama-French risk-free rate. This is inconsistent with previous results herein and in other papers that find that Sharpe Ratios are lower for higher risk assets unless this finding can be interpreted as utility stocks having more risk than non-regulated stocks. The standard deviations on Table 1 suggest that utility stock return volatilities are as high as the stock returns of non-regulated firms. However, similar model estimates of portfolios of common stocks yield unstable results, such as negative as well as positive return-risk slopes when the intercept is not restricted to zero. See Campbell (1987), Glosten et al. (1993), Harvey (2001), and Whitelaw (1994).

Stock market results are highly sensitive to empirical model specification. Many studies do not consider the impact of a zero-intercept prior restriction on the stability of their results. This simple innovation has led to more consistent results in modeling stock market risk-return relationships, and therefore we have included it in this paper.

The estimation of the consumption asset pricing model for utility stock equity-debt risk premia shows that the use of bond-rating risk-differentiated risk premia are validated as their risk-return relationships are well-fitted by theoretical and empirical models of risk and return. Therefore, these data impound good representations of the risk and reward relationship.

One concern is the intertemporal stability of the alphas. Figure 1 plots the utility stock portfolio alpha (using the Fama-French R_f to calculate the premium) and its standard error for 240 month rolling regressions of the model estimated with GARCH-M in the same manner as described above to review the intertemporal stability of the alpha. A 20-year period was used for each estimation to trade off timeliness with sufficient observation of up and down stock market regimes and business cycles. This resulted in 720 estimated alphas from 1947 to 2007. The results show that the utility alpha is stable to the extent that the algebraic sign is always positive and generally significant, therefore the nature of utility stocks are assets that are not and have never been hedges during the second half of the twentieth century up to the present. The value of the alpha does change substantially. The mean of the alpha is 4.40 with a range from -0.11 (insignificantly different from 0) to 11.66. As a comparison, the alpha for the CRSP value-weighted stock index was also estimated with rolling regressions in the same manner and for the same time period. Figure 2 is a plot of the CRSP alpha and standard error. Note that the general stock market alpha is similar to that of utility stocks. They are all positive and almost all statistically significant and follow a strikingly similar cycle. Figure 3 plots both the utility and stock market alphas and demonstrates the similarity. The correlation coefficient between the utility and stock market alphas is 0.88. Recalling that the alpha is a Sharpe Ratio, we see that return to risk ratio does change substantially. This is consistent with the results in Pilotte and Sterbenz (2006).

One other interesting observation is that the standard errors of the alphas are highly stable over the study period and are very similar in magnitude regardless of the size of the corresponding alpha. Whereas the alpha follows a cyclical pattern, the volatility in alpha is highly stationary around a constant, long-run mean.

The GARCH-M model estimations of the consumption asset pricing model were specified with variance as the measure of volatility. We also performed the same model estimations with alternative specifications of volatility such as the standard deviation and the log of variance and the results were not sensitive to this specification.

4 Application

We apply the model in this section to compare the cost of common equity capital estimates with the DCF and CAPM models. Using EViews© Version 6.0, we estimated the model coefficients (α, $\beta's$) over rolling 24 month periods ending December 2008.

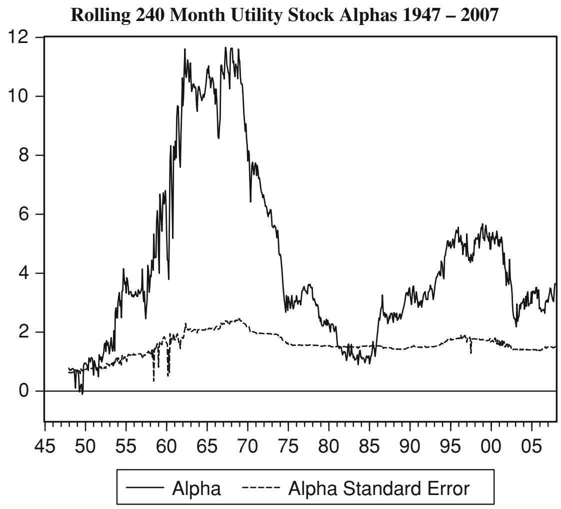


Fig. 1 Rolling 240 month utility stock alphas 1947–2007

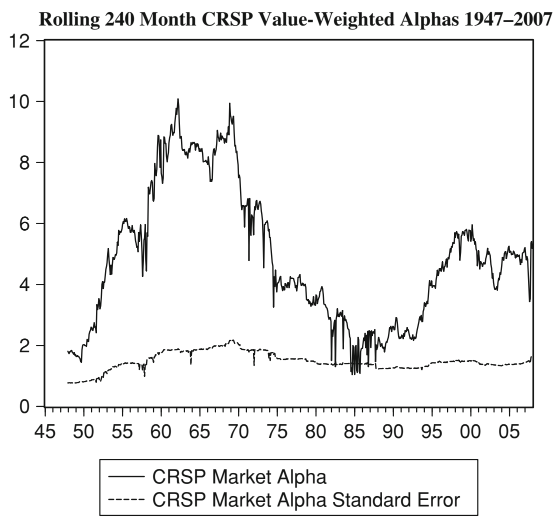


Fig. 2 Rolling 240 month CRSP value-weighted alphas 1947–2007

We repeated the estimation over 5, 10, 15, 20 and 79 year periods.[3] Predicted monthly variances (σ_{t+1}^2) were generated from these estimations to produce predicted risk premiums that were calculated by multiplying the predicted variance by the "α" slope

[3] We did not include the results of the 10 and 15 year estimations to abbreviate the amount of empirical results presented since they added no material insights beyond those already presented.

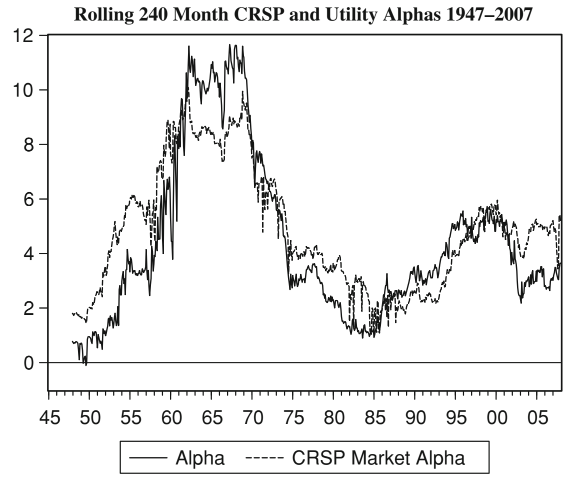


Fig. 3 Rolling 240 month CRSP and utility alphas 1947–2007

Table 3 Estimates of expected risk premia

	Mean (%)		Range (%)		Standard deviation (%)	
	Average	Spot	Average	Spot	Average	Spot
Ibbotson Associates data						
79-years	9.59	5.76	8.74–9.96	2.62–22.60	0.32	5.24
20-years	6.77	6.94	4.99–8.50	2.24–28.95	0.95	6.88
5-years	4.20	10.25	−98.49–11.62	−100.00–39.65	22.00	26.61
S&P Utility Index						
79-years	5.28	2.90	4.30–5.28	1.65–8.15	0.32	1.60
20-years	3.93	3.51	2.78–5.03	2.18–6.88	0.57	1.11
5-years	31.82	326.63	7.77–156.97	6.12–6465.74	31.47	1283.51

coefficient. To test the stability of the predicted risk premia over time, the predicted risk premia were calculated using either the predicted variance over each entire time period or the last monthly (spot) predicted variance. Table 3 presents the mean predicted risk premia, the range of predicted premia and the standard deviations for each time period. It is clear from the results that the risk premia are more stable over the rolling 24 month period when calculated using the average predicted variance compared with using the spot variance. Secondly, the 20 and 79 year means are substantially more stable and reasonable in magnitude than the 5 year means.

Next, given the lessons from the analyses above, we apply the model to mechanically[4] estimate the cost of common equity for 8 utility companies using the model and

[4] The term "mechanically" in this context means that the resulting values have been developed in a consistent manner with the same inputs across all utility stocks but no subjective judgment was used to develop final values for each specific utility stock application.

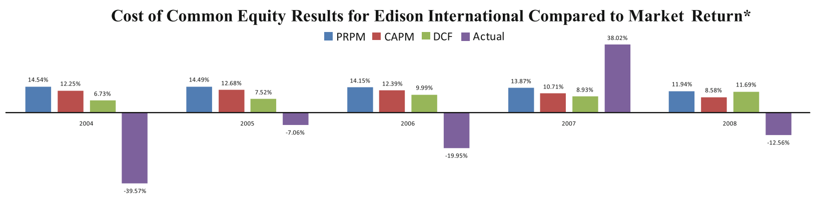
the DCF and CAPM as comparisons. We also calculated the realized market return for comparison. Two publicly-traded electric, electric and gas combination, gas, and water utilities respectively were chosen for the application. The Gordon (1974) DCF and CAPM models are used in many utility regulatory jurisdictions in the US.

The DCF was applied using a dividend yield, D_0/P_0, derived by dividing the year-end indicated dividend per share (D_0) by the year-end spot market price (P_0). The dividend yield is grown by the year-end I/B/E/S five year projected earnings per share growth rate (g) to derive $D_0(1+g)/P_0$. The one-year predicted dividend yield is then added to the I/B/E/S five-year projected EPS growth rate to obtain the DCF estimate of the cost of common equity capital, k. This study was conducted for the 5 years ending 2008.

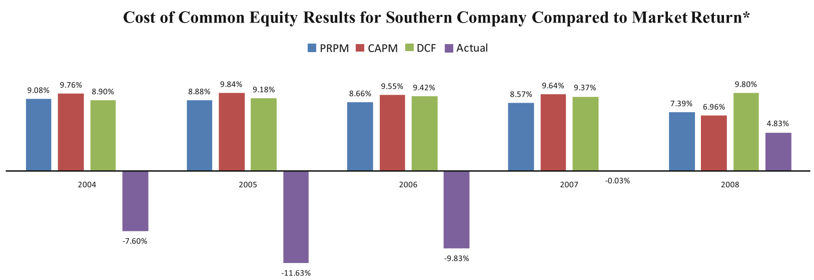
The CAPM was applied by multiplying the Value Line beta (β) available at year-end for each company by the long-term historic arithmetic mean market risk premium ($R_m - R_f$). $R_m - R_f$ is derived as the spread of the total return of large company common stocks over the income return on long-term government bonds from the Ibbotson SBBI 2009 Valuation Yearbook. The resulting company-specific market equity risk premium is then added to a projected consensus estimate of the yield on 30-year U.S. Treasury rate provided by Blue Chip Financial Forecasts as the risk-free rate (R_f) to obtain the CAPM result. This study was also conducted over the 5 years ending 2008.

Figures 4–11 show the histograms of the cost of common equity capital estimations for each of the eight public utility stocks and the realized market returns in the forthcoming year. The consumption asset pricing model appears to track more consistently with the CAPM than with the DCF which seems to produce generally lower values than the other methods. The consumption asset pricing model results are similar to the CAPM. The model and the CAPM compete as the best predictor of the rate of return on the book value of common equity (not shown but available upon request), but none of the expected returns were good predictors of market returns. That does not infer that they were not good predictors of *expected* market returns. These results are an initial indicator that the consumption asset pricing model provides reasonable and stable results. This paper does not suggest at this early juncture that the consumption asset pricing model is superior to the CAPM or DCF, although it is based on far less restrictive assumptions than these other models. For example, both the DCF and CAPM assume that markets are efficient. Many assume that the DCF requires that the market-to-book ratio to always equal one, whereas the long-term value for the Standard and Poor's 500 is equal to 2.34. The CAPM assumes that investors demand higher returns for higher volatility and that the minimum required return is the risk-free rate, whereas the consumption asset pricing model allows for investors to require returns less than the risk-free rate for stocks that may have relatively higher volatility but are hedging assets that have desirable return fluctuation patterns that offset downturns in the business cycle. Unlike the CAPM, the model prices the risk to which investors are actually exposed, whether it's systematic risk or not. Some investors are diversified and some are not; the model prices whatever risk to which the aggregate of investors of the specific stock is exposed.

We find that the consumption asset pricing model should be used in combination with other cost of common equity pricing models as additional information in the devel-



* Market returns calculated for the following years: 2005 -2009



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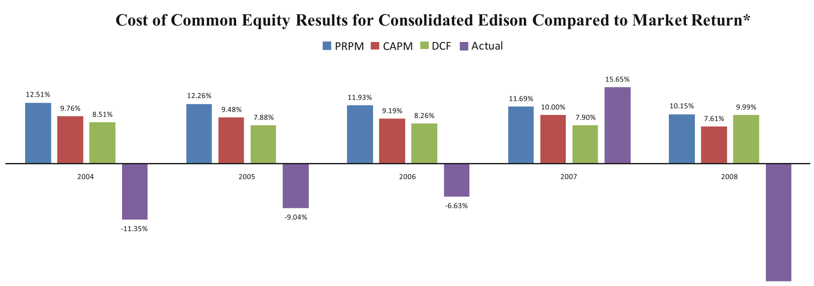
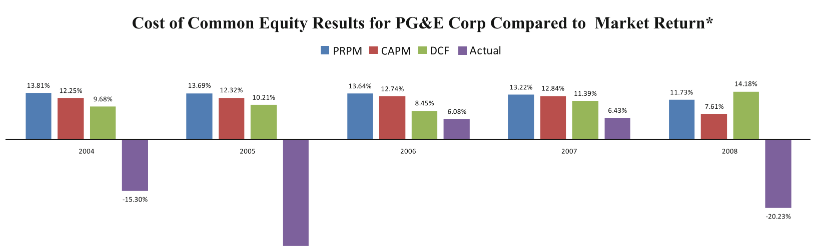


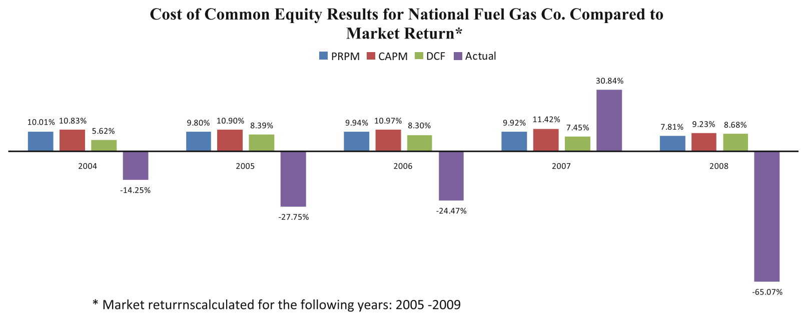
* Market returns calculated for the following years: 2005 - 2009

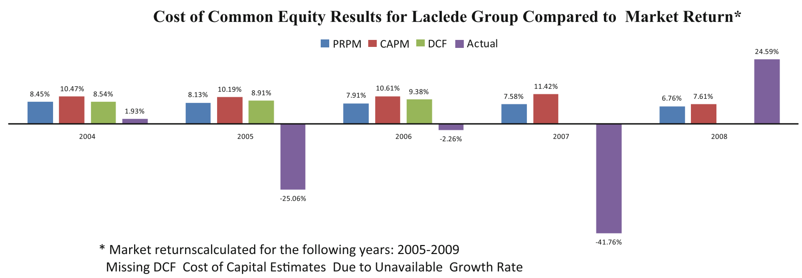


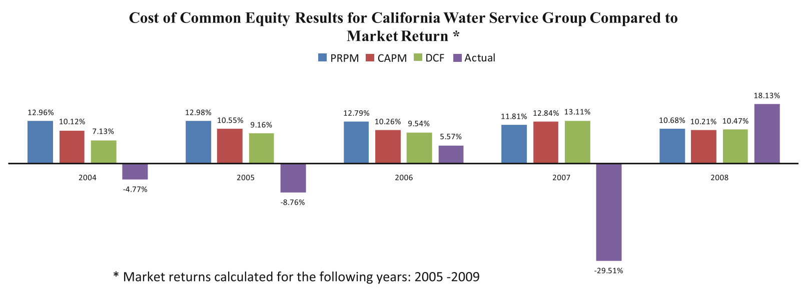
* Market returns calculated for the following years: 2005 -2009

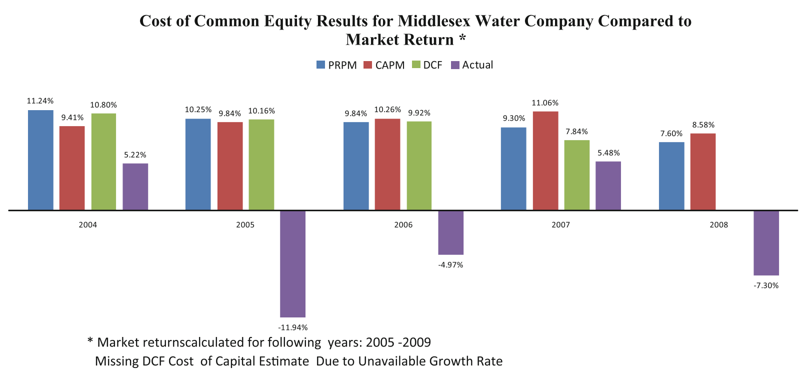
Figs. 4–11 Comparison of the cost of common equity estimates and market

opment of a cost of common equity capital recommendation. Practitioners may find the modeling methods and the use of relatively advanced econometric methods rather cumbersome. The software for performing these estimations is readily available from EViews© and SAS©; two commonly available software packages at utilities, consult-









Figs. 4–11 continued

ing firms and financial firms. Recent Ph.D. and M.S. holding members of research departments of investment and consulting firms have ready access to the model and methods discussed in this paper, although it will require years for these tools, like any "new" technology, to diffuse into standard use. Another problem is that the model requires a substantial time series history on stock returns data to develop stable estimates of risk premia This is problematic especially for the electric and gas utility industries that have consolidated with many mergers in the recent past. This problem can be addressed by developing and predicting the value-weighted risk premium of a portfolio of similar stocks such as electric utilities that have nuclear generating assets. The specific stock in question would be included in the returns index with a weight based on market capitalization that would go to 0 when the stock price history is no longer existent reaching back into the past.

5 Conclusion

The purpose of this paper is to introduce, test empirically and apply a general consumption based asset pricing model that is based on a minimum of assumptions and restrictions that can be used to predict the risk premium to be applied in estimating the cost of common equity for public utilities in regulatory proceedings. The results support the simple consumption-based asset pricing model that predicts the ex ante risk premium with a conditionally predicted volatility in risk premium. The estimates of the cost of common equity from the consumption asset pricing model compare well with rates of return on the book value of common equity and with the CAPM, although both the model and the CAPM results are substantially higher than the DCF. This is quite common in the practice of the cost of common equity in the utility industry. The results of the model are stable and consistent over time. Therefore the model should be considered as it provides additional evidence on the cost of common equity in general and specifically in public utility regulatory proceedings. Secondly, the use of bond-rated yields to predict risk differentiated equity-to-debt risk premia is supported by the empirical evidence and therefore should be applied in estimating the cost of common equity. Finally, the robust empirical evidence on the positive risk-return relationship also shows that utility stocks are not a consumption hedge and are not good hedging securities against contractions in the economy. The model and estimation methodology presented in this paper provide a relatively simple tool to determine whether any asset is a hedge to adverse changes in the business cycle through the level of consumption in the economy.

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Comparative Evaluation of the Predictive Risk Premium Model, the Discounted Cash Flow Model and the Capital Asset Pricing Model for Estimating the Cost of Common Equity

The regulatory process for setting a utility's allowed rate of return on common equity has generally relied upon the Gordon Discounted Cash Flow Model and Capital Asset Pricing Model. The Predictive Risk Premium Model, introduced a year ago, resolves several of the widely known problems with these models. Further testing since its introduction a year ago suggests that it produces stable results which are consistent over time.

Richard A. Michelfelder, Pauline M. Ahern, Dylan W. D'Ascendis and Frank J. Hanley

I. Introduction

The lead article in the July 2008 issue of this *Journal*, "Integrating Renewables into the US Grid: Is it Sustainable," by Professors Peter Mark Jansson and Richard A. Michelfelder,[1] called for the reregulation of the electric utility industry and putting the planning of generation assets, whether renewable or not, back in the hands of the experts and those ultimately responsible for reliability, the electric utilities. During the last 10 years or so,

 1040-6190/$–see front matter http://dx.doi.org/10.1016/j.tej.2013.04.005

states have been backpedaling on deregulation and therefore methods for estimating the cost of common equity and the allowed rate of return have generated new interest as regulating rate of return is not going away as once thought.

The regulatory process for setting a public utility's allowed rate of return on common equity has generally relied upon the familiar Gordon Discounted Cash Flow Model (DCF) and Capital Asset Pricing Model (CAPM). Despite the widely known problems with these models, there has been little initiative to adopt more recently developed asset pricing models with fewer limiting assumptions and requiring less subjective judgment than these traditional models. In December 2011, the article "New Approach to Estimating the Cost of Common Equity Capital for Public Utilities,"[2] published in *The Journal of Regulatory Economics*, introduced the Predictive Risk Premium Model (PRPM). The PRPM trademark refers to a general, yet simple, consumption-based asset pricing model of the risk/return relationship for common stocks which can be used to estimate the cost rate of common equity (ROE). The stability and consistency of the results of PRPM and the ex ante, i.e., expectational, nature of those results indicate that the model should be used to provide additional input into the process of determining an allowed rate of return on common equity for public utilities.

Since publication, more exhaustive empirical testing of the PRPM was conducted for the four utility industry groups which comprise the AUS Utility Reports[3] universe of publicly traded utilities: an electric utility group; a combination electric and natural gas distribution utility group; a natural gas distribution utility group, and a water utility group. The empirical testing confirms the conclusion of the original *Journal of Regulatory Economics* article: the PRPM produces stable results which are consistent over time.

Despite the widely known problems with these models, there has been little initiative to adopt more recently developed asset pricing models with fewer limiting assumptions and requiring less subjective judgment.

II. Development of the PRPM

The cost rate of common equity is not directly observable in the capital markets and must be inferred using various financial models. The most commonly used cost of common equity models in the regulatory arena are the aforementioned DCF and the CAPM. Since these models are based upon many restrictive assumptions, they involve a significant amount of analyst subjectivity in their application, resulting in much debate over the application and results of these models.

The empirical approach to the PRPM is based upon the work of Robert F. Engle, Ph.D.,[4] who shared the Nobel Prize in Economics in 2003 "for methods of analyzing economic *time series* with time-varying volatility (*ARCH*),"[5] with "ARCH" standing for autoregressive conditional heteroskedasticity. In other words, volatility (variance) changes over time and is related to itself from one period to the next, especially in financial markets. Engle discovered that the volatility (usually measured by variance) in prices and returns clusters over time. Therefore, volatility is highly predictable and can be used to predict future levels of risk. The theoretical asset pricing model was recently developed in the *Journal of Economics and Business* in December 2011 by Rutgers University professors Richard Michelfelder and Eugene Pilotte.[6]

In this study, the PRPM estimates the risk/return relationship directly using the outcomes of investors' historical pricing decisions and actual long-term U.S. Treasury security yields, with the predicted equity risk premium generated by the prediction of volatility, i.e., the risk, based upon the volatility of past equity risk premiums for the AUS Utility Reports universe of companies.

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III. Estimation Method

The statistical details of the estimation method of the PRPM can be found in the original article in the *Journal of Regulatory Economics*, "New Approach to Estimating the Cost of Common Equity Capital for Public Utilities." Essentially, there are two steps to the application of the PRPM. First, predicted volatility, i.e., risk, is derived based upon previous volatility plus previous prediction error, because volatility is highly predictable and correlated over time. Second, the predicted volatility can then be used to generate the predicted equity risk premium (ERP) by multiplying it by the GARCH coefficient, i.e., the slope of the predicted volatility. A risk-free rate is then added to the ERP to estimate the ROE, i.e., the market based cost of common equity.

IV. Application of the PRPM to Publicly Traded Utility Companies

The PRPM was applied to the companies comprising the AUS Utility Reports' utility industry groups: the electric, combination electric and natural gas distribution, natural gas distribution, and water groups. The PRPM variances were calculated monthly for each individual utility beginning with the first available monthly data included for each individual utility in the University of Chicago Booth School of Business' Center for Research in Security Prices (CRSP) and corresponding monthly long-term U.S. Treasury bond yields from Morningstar's *Ibbotson SBBI – 2012 Valuation Yearbook – Market Results for Stocks, Bonds, Bills and Inflation – 1926–2011 (SBBI)* through 72-month ending periods, i.e., January 2006 through December 2011.

Using EViews Version 7.2, the PRPM coefficients and predicted monthly variances were estimated as described in the *JRE* article for each time series of equity risk premiums. Consistent with the conclusion drawn in the *JRE* article, the predicted equity risk premiums were calculated using the averaged predicted volatilities (variances) over the entire time period for which CRSP data were available for each utility, multiplied by the GARCH, or slope, coefficient generated through EViews for each time series. To calculate the PRPM cost rate of common equity for each utility, the average predicted utility specific equity risk premium through each month ending from January 2006 through December 2011 was then added to the projected consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the next six quarters by the reporting economists in the concurrent *Blue Chip Financial Forecasts (Blue Chip)*.

The DCF was applied in a simple manner, using a dividend yield, D_0/P_0, derived by dividing the month-end indicated dividend per share (D_0) by the month-end closing market price (P_0) for each utility. The dividend yield was then grown by the month-end I/B/E/S consensus five-year projected earnings per share (EPS) growth rate (g) to derive ($D_0\ (1 + g)/P_0$). The one-month predicted dividend yield was then added to the concurrent month's I/B/E/S consensus

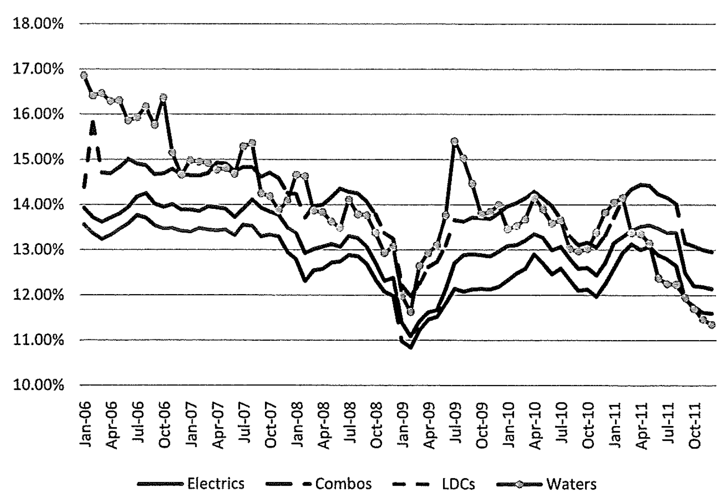

Figure 1: Indicated Return on Common Equity Based upon the PRPM for the AUS Utility Reports Companies

 1040-6190/$–see front matter , http://dx.doi.org/10.1016/j.tej.2013.04.005

five-year average projected EPS growth rate to obtain the DCF estimate of the cost of common equity capital, *k*. The DCF estimates were also calculated for each month from January 2006 through December 2011.

The CAPM was applied by multiplying Value Line Inc.'s beta (β),[7] for each utility, by the long-term historical arithmetic mean market equity risk premium ($R_m - R_f$) through the previous year. ($R_m - R_f$) was derived as the spread of the total return of large company common stocks over the income return on long-term government bonds from the annual *SBBI Valuation Yearbooks* for the years ending 2005 through 2010. The resulting utility-specific equity risk premium was then added to the same projected consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the next six quarters by the reporting economists in the concurrent *Blue Chip* discussed above, to obtain the CAPM estimate of the cost of common equity capital, *k*. The CAPM estimates were also calculated for each month from January 2006 through December 2011.

Finally, the results for each of the models, the PRPM, DCF, and CAPM, were averaged for each utility group.[8] **Figure 1** presents the average PRPM results for each of the AUS Utility Reports utility groups for each month from January 2006 through December 2011.

Figure 1 shows that indicated ROEs derived from the PRPM were stable for all utility groups until the global financial crisis of 2008–2009. During 2008 and 2009, the PRPM-derived ROEs decline, which in the authors' opinion, was a result of a "flight to quality" by investors, i.e., the willingness of an investor to accept a lower, but more certain, return during financial downturns. Figure 1 also indicates that the PRPM-derived ROEs for the electric, combination electric and natural gas distribution, and natural gas distribution utility groups follow a nearly identical pattern throughout the 72-month period, with the water utility group following a similar, but more volatile pattern.

Figures 2–5 present a comparison of the average PRPM, DCF, and CAPM cost of common equity estimates for each AUS

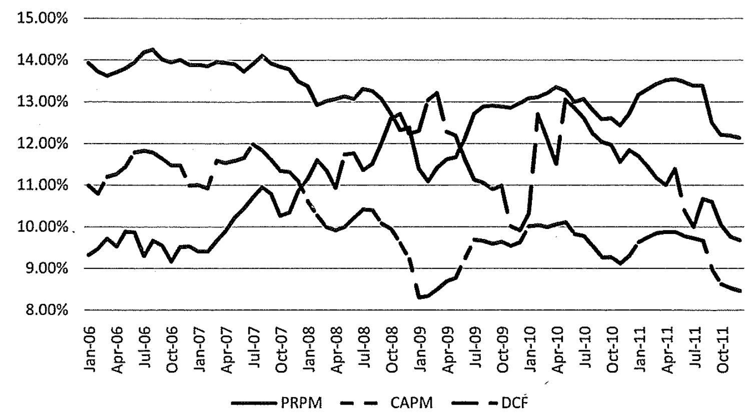

Figure 2: Indicated Return on Common Equity Based upon the PRPM, CAPM and DCF Methodologies for the AUS Utility Reports Electric Companies

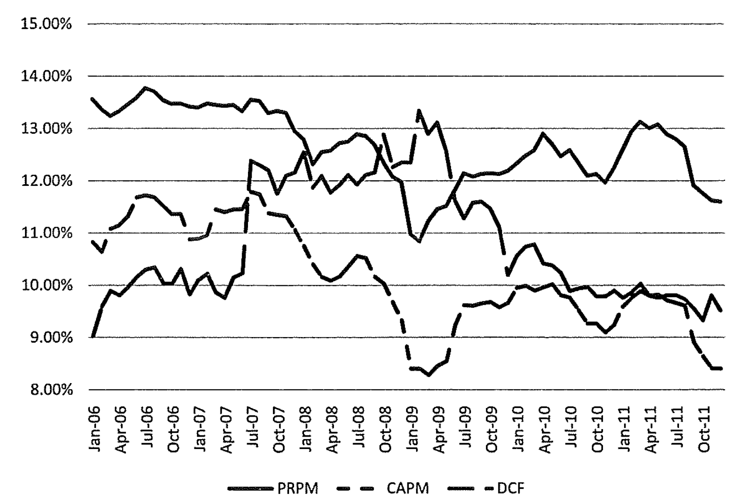

Figure 3: Indicated Return on Common Equity Based upon the PRPM, CAPM, and DCF Methodologies for the AUS Utility Reports Combination Companies

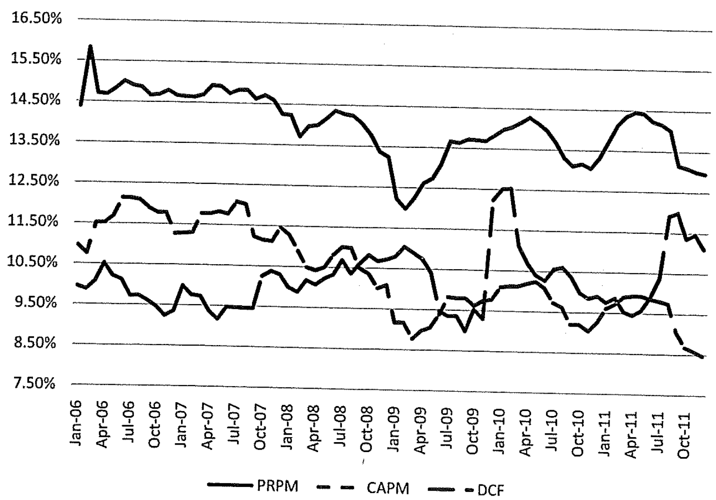

Figure 4: Indicated Return on Common Equity Based upon the PRPM, CAPM and DCF Methodologies for the AUS Utility Reports Gas Companies

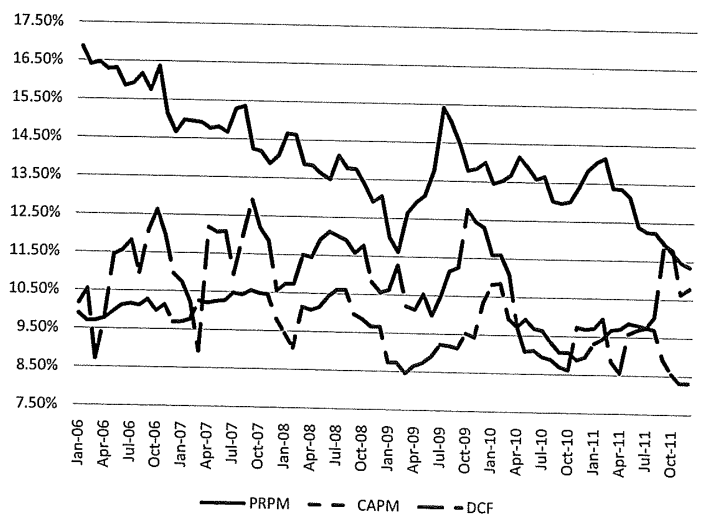

Figure 5: Indicated Return on Common Equity Based upon the PRPM, CAPM and DCF Methodologies for the AUS Utility Reports Water Companies

Utility Reports utility industry group, i.e., the electric utility group; the combination electric and natural gas distribution utility group; the natural gas distribution utility group; and, the water utility group for each month from January 2006 through December 2011.

Figures 2–5 clearly show that, for the most part, the PRPM produces a higher average indicated ROE than both the DCF and CAPM. This is due to the fact that the PRPM prices *all* of the risk that investors actually face collectively. In contrast, the CAPM prices systematic risk (that investors face only if they have a perfectly diversified portfolio, which does not exist) and the DCF uses accounting-based, not market-based, I/B/E/S consensus five-year projected EPS growth rates.

V. Conclusion

In the authors' opinion, the PRPM benefits ratemaking with an additional model to estimate ROE. To that end, the authors have been including the PRPM in their rate-of-return testimonies and the model has been presented publicly in several venues.[9]

Its results are stable and consistent over time. It is not based upon restrictive assumptions, as are the DCF and CAPM. The PRPM is also not based upon an *estimate* of investor behavior, but rather, upon a statistical analysis of *actual* investor behavior by evaluating the results of that behavior, i.e., the volatility (variance) of historical equity risk premiums. In contrast, subjective decisions surround the choice of the inputs to both the DCF and CAPM, from the choice of the time period over which to measure the dividend yield for the DCF, the choice of the DCF growth rate (e.g., historical or projected, earnings per share or dividends per share, and the like), to the selection of the appropriate beta (e.g., adjusted or unadjusted), market equity risk premium (e.g., historical or projected) and the appropriate risk-free rate (e.g., historical or projected and/or long vs. short term) for the CAPM. In addition, as previously discussed, the CAPM exclusively prices systematic risk. In contrast, the PRPM prices *all* of the risk actually faced collectively by investors, because the model does not assume that investors' portfolios are perfectly diversified containing no unsystematic risk.

In addition, the inputs to the PRPM are widely available. The GARCH coefficient is calculated with the relatively inexpensive EViews, or other statistical, software, based upon the realized ERP, i.e., total returns minus the risk-free rate. The only subjective decisions to be made when applying the PRPM relate to which risk-free rate to use, e.g., long-term or short-term, and over what time period to estimate the PRPM-derived ROEs.

For all of these reasons, the authors conclude that the PRPM should be considered as appropriate additional evidence to measure the cost of common equity in regulatory rate setting for public utilities.■

Endnotes:

1. Peter Mark Jansson and Richard A. Michelfelder, *Integrating Renewables into the US Grid: Is It Sustainable?* ELEC. J.July 2008, at 9–21.

2. Pauline M. Ahern, Frank J. Hanley and Richard A. Michelfelder, *New Approach to Estimating the Cost of Common Equity Capital for Public Utilities*, J. REG. ECON.(2011) 40, at 261–78.

3. AUS Monthly Utility Reports is a monthly pocket reference book covering the electricity, combination electricity & natural gas distribution, natural gas distribution, and water companies which have publicly traded common stock. The monthly reports provide comprehensive information on key ratios and industry rankings based upon the financial statistics presented in the report.

4. Professor Emeritus, University of California, San Diego, and currently the Michael Armellino Professor in Management of Financial Services at New York University's Stern School of Business.

5. See www.nobelprize.org.

6. Richard Michelfelder and Eugene Pilotte, *Treasury Bond Risk and Return, the Implications for the Hedging of Consumption and Lessons for Asset Pricing*, J. ECON. & BUS.(2011) 63, at 605–37.

7. Using a proprietary data base available at mid-March, June, September, and December at the end of each year, from 2006–2011 from Value Line, Inc.

8. The results shown in the accompanying figures represent AUS Utility group averages of only those utilities in each group for which it was possible to estimate all three models in any given month. For example, if ABC Utility did not have the I/B/E/S consensus growth rate necessary to calculate the DCF in a given month, that utility's PRPM and CAPM were not included in the group average for that month.

9. Edison Electric Institute Cost of Capital Working Group (Webinar Oct. 2012); NARUC Staff Subcommittee on Accounting & Finance (Sept. 2012 and Mar. 2010); National Association of Water Companies Finance/ Accounting/Taxation and Rates & Regulations Committees (Mar. 2012); NARUC Water Committee (Feb. 2012); Wall St. Utility Group (Dec. 2011); IN Utility Regulatory Commission Cost of Capital Task Force (Sept. 2010); Financial Research Inst. of the Univ. of Missouri Hot Topic Hotline Webinar (Dec. 2010); and Center for Research in Regulated Industries Annual Eastern Conference (May 2010 & May 2009).

Subjective decisions surround the choice of the inputs to both the DCF and CAPM.

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Treasury Bond risk and return, the implications for the hedging of consumption and lessons for asset pricing

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A B S T R A C T

All consumption-based models of asset pricing imply that the relation between the conditional mean and conditional volatility of *any* asset reflects the effectiveness of holding that asset as a hedge against intertemporal variation in the marginal utility of consumption. For Treasury Bonds of various maturities, we find significant positive relations. Our empirical findings support the conclusion that investors must sell bonds short to hedge shocks to marginal utility, because realized bond returns tend to be high (low) when investors least (most) desire an additional dollar of consumption. Implications for special cases of the general consumption-based model are also discussed.

1. Introduction

All consumption-based models of asset pricing imply that the relation between the conditional mean and conditional volatility of *any* asset reflects the effectiveness of the asset as a hedge against intertemporal variation in the marginal utility of consumption. The relation is negative if a long position in an asset hedges shocks to the marginal utility of consumption. The relation is positive if a long position adds to consumption risk. We estimate the relation between the conditional mean and conditional volatility of excess returns on U.S. Treasury securities and find evidence of significant positive relations for all maturities. Our full sample results indicate that long positions in Treasury Bonds do not hedge shocks to the marginal utility of consumption. To hedge effectively against such shocks an investor must sell short or sell futures on bonds. In terms of statistical significance and robustness

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to changes in methodology, the positive relation is especially reliable for bond maturities of 5 years or less, so short positions on shorter-maturity bonds are the most statistically reliable means for an investor to hedge the marginal utility of consumption.

The general consumption-based model upon which we base our tests requires only minimal assumptions. Models such as the capital asset pricing model (CAPM), intertemporal capital asset pricing model (ICAPM) of Merton (1973), the intertemporal asset pricing model of Campbell (1993), and the habit-persistence model of Campbell and Cochrane (1999) are special cases.[1] Specializations of the general model add additional structure, but do not change the implications that are the focus of our empirical tests. The intuition of the general model is straightforward. A pure hedging asset has realized returns that are perfectly positively correlated with the marginal utility of wealth.[2] It provides high payoffs during "bad times" when the marginal utility of consuming an additional dollar of wealth is high and low payoffs during "good times" when the marginal utility of consuming an additional dollar of wealth is low. The volatility of the asset's return is desirable and investors are willing to pay more for the asset, because holding the asset decreases intertemporal variation in the holder's marginal utility. Thus, the key characteristics of a hedging asset are a negative risk premium and a perfect negative correlation between the conditionally expected excess return and conditional volatility of the asset. On the other hand, an asset that has returns that are perfectly negatively correlated with the marginal utility of wealth provides high payoffs when times are good and low payoffs when times are bad. The volatility of the asset's return is undesirable because it increases intertemporal variation in the holder's marginal utility. The expected risk premium on such an asset is positive and perfectly positively correlated with its conditional volatility. A short, rather than long, position in the asset is required to hedge consumption risk. Our empirical results for bonds are consistent with the latter case, indicating that realized returns on bonds tend to be high in good times when the marginal utility of receiving an additional dollar of wealth is low.

The beauty of the general consumption-based model is that it provides a simple and straightforward test of the hedging effectiveness of any asset that requires only modeling the first two moments of the asset's return. The test does not require consumption data, nor does it require that the researcher choose a specific model of investor preferences. The model's predictions regarding the first two moments of returns hold for any asset, for any two periods of a multi-period model, and require no assumptions regarding complete markets, return distributions, time- or state-separable utility, or the existence of labor income or human capital.

In addition to evidence of hedging effectiveness, our results provide evidence regarding which special cases of the consumption-based model capture key aspects of asset returns. Our full sample results are consistent with the conclusion that realized returns on Treasury Bonds are high when investors least value, and low when investors most value, the benefits of an additional dollar of consumption. Thus, for a special case of the consumption-based model to accurately reflect investor preferences, it must explain why investors associate bad times of high marginal utility with periods of low realized and high expected bond returns. Special cases that assume that the marginal utility of consumption is a function of at most wealth and investment opportunities, such as the ICAPM specializations of Merton (1973) and Campbell (1993), do not do so. Unless one assumes that the coefficient of relative risk aversion is very low (less than one), these specialized models associate bad times with low expected returns. Explaining why investors associate bad times with high expected returns requires a model that captures the fact that investors are concerned not only with the wealth effects of holding assets, but with the fact that assets do poorly at particular times or in particular states of nature (recessions). For example, Campbell and Cochrane (1999) do so by adding an argument to the utility function, habit that enters nonseparably over time

Turning to empirical results, we find that neither the sign nor the significance of the estimated relation between bond risk and return is sensitive to changes in methodology known to influence inferences in the literature on stock risk and return. Specifically, the results are similar whether

[1] For detailed discussion of the relation of these and other asset pricing models to the general model see Cochrane (2006, 2007).
[2] Once the consumer/investor has optimized, the marginal utility of an additional dollar of wealth is the same for all uses.

the conditional variance is modeled using only financial conditioning variables, a simple generalized autoregressive conditional heteroskedasticity in mean (GARCH-M) model, a GARCH-M model that incorporates financial conditioning variables in the estimation of the conditional variance, or GARCH-M models that allow for asymmetries in the conditional variance equation. While all of our empirical models provide evidence consistent with a positive risk–return relation for Treasury Bonds, the strongest results are for the model that incorporates both financial conditioning information and GARCH effects in estimating the conditional variance. Thus, combining alternative methods of estimating the conditional variance reinforces inferences regarding the sign of the risk–return relation.

The general consumption-based model permits the reward to bond volatility to vary over time, so we examine the linearity and stability of the relation between conditional mean and conditional variance. For each model of conditional variance and each bond maturity, regression analysis indicates that financial conditioning information explains variation in bond excess returns that is not related to changes in the conditional variance. The fact that a time invariant linear model of the bond risk–return relation is rejected suggests that the reward to bond volatility does change over time.

To provide evidence on the impact of changing reward to volatility on the stability of the risk–return relation, we examine rolling correlations between "best estimates" of the conditional mean excess return and conditional variance. The rolling correlations show substantial variation over time in the short-term relation between bond risk and return. The rolling correlations for all maturities tend to move together, but the range of variation increases with bond maturity. For each maturity there are periods during which the rolling correlations are negative, which suggests that the hedging effectiveness of bonds may have varied during our sample period.

The remainder of this paper is organized as follows. Section 2 reviews related literature. Section 3 provides theoretical context. Section 4 describes the data. Section 5 presents our empirical model of conditional mean excess returns and diagnostic tests of the stability of the model. Section 6 presents our empirical results. Section 7 evaluates the linearity and stability of the relation between the conditional mean and conditional variance. Section 8 concludes.

2. Related literature

Two studies report direct evidence regarding the intertemporal relation between the conditional mean and conditional volatility of monthly bond returns. Engle, Lilein, and Robins (1987) use an ARCH-M framework to estimate the relation between the conditional mean and conditional standard deviation of monthly excess holding period returns on two-month Treasury bills and twenty-year AAA rated corporate bonds. They find positive coefficient estimates on volatility in the expected return regressions for both return series. The coefficient for the two-month bill is significant at the 0.01 level, while that for corporate bonds is significant at the 0.10 level. Campbell (1987) estimates the conditional mean and conditional variance of monthly excess returns on two-month Treasury bills, six-month Treasury bills, and a portfolio of five-to-ten-year Treasury Bonds, where both moments are modeled as functions of financial conditioning variables. Campbell (1987) reports correlations between the fitted moments of 0.625 for the two-month bill, 0.835 for the six-month bill, and 0.029 for the long-term bond portfolio. While the evidence reported in these studies is limited in terms of the bond maturities examined, the two studies are consistent in reporting a strong positive relation between risk and return for short-term bills and a weak positive relation for long-term bonds.[3] No study presents a direct test of the stability of the relation between conditional expected excess returns and volatilities for bonds.

Contrary to the case of bonds, there are many studies that report estimates of the relation between the conditional mean and conditional volatility of monthly stock market returns. Results are very sensitive to changes in the methodology used to estimate the conditional volatility. Since studies by

[3] In related work, Fama (1976) and Klemkosky and Pilotte (1992) document positive relations between excess returns and the volatility of the one-month bill rate for a variety of bill and bond maturities. Such results imply a positive relation between a bond's excess return and own volatility when the term structure is determined by a single state variable. However, Litterman and Scheinkman (1991) find that at least three state variables are required to adequately model the term structure.

Campbell (1987), Campbell and Ammer (1993), and Fama and French (1993) find that bond and stock excess returns are related to common predictor variables, robustness may be an issue for bonds as well as stocks. On the other hand Reilly, Wright, and Chan (2000) and Jones and Wilson (2004) document differences in the time series properties of stock and bond returns, so robustness may not be an issue. As a precaution, we explore changes in methodology know to influence results in the stock literature.[4]

A review of studies of monthly stock returns such as French, Schwert, and Stambaugh (1987), Glosten, Jaganathan, and Runkle (1993), Campbell (1987), Whitelaw (1994) and Harvey (2001) indicates that results are sensitive to whether the conditional variance is modeled using only financial conditioning variables, a simple GARCH-M model, a GARCH-M model that incorporates financial conditioning variables in the estimation of the conditional variance, or GARCH-M models that allow positive and negative shocks to returns to have different impacts on the conditional variance. We also use monthly data, so we examine the robustness of our results to the aforementioned changes in methodology.[5]

3. Theoretical context

Consider the intertemporal choice problem of a representative investor who maximizes the conditional expectation of the utility of current and future consumption. In that case, assets can be priced as the conditional expected value of the product of their payoff and a stochastic discount factor,

$$P_{i,t} = E_t[M_{t+1}(P_{i,t+1} + I_{i,t+1})], \tag{1}$$

where $P_{i,t}$ is the price of asset i at time t, $I_{i,t+1}$ is the asset's income at $t+1$, and M_{t+1} is the stochastic discount factor.[6] The discount factor is the marginal rate of substitution, defined as $M_{t+1} \equiv \beta U_C(C_{t+1}, \boldsymbol{x}_{t+1})/U_C(C_t, \boldsymbol{x}_t)$, where β is the time preference parameter and $U(C_t, \boldsymbol{x}_t)$ defines utility as a function of time t consumption, C_t, and a vector, $\boldsymbol{x}_t$, of other variables that enter into the utility function. Utility is assumed to be an increasing and concave function of consumption. The additional arguments, $\boldsymbol{x}_t$, admit the possibility that utility may be a function of other variables such as state variables and may be nonseparable over time, goods, or states of nature. The C subscript denotes the first derivative of utility with respect to consumption. Eq. (1) and the equations that follow hold for both real and nominal values as long as all values, including M_{t+1}, are expressed consistently in either real terms or nominal terms. They hold for any asset for any two periods of a multi-period model and require no assumptions regarding complete markets, return distributions, time- or state-separable utility, or the existence of labor income or human capital. Making such assumptions adds additional structure to the model, but does not change any of the implications discussed here.

Defining the gross return (one plus the net return) as $R_{i,t+1} = (P_{i,t+1} + I_{i,t+1})/P_{i,t}$, Eq. (1) can be rewritten in terms of asset returns as

$$1 = E_t[M_{t+1}R_{i,t+1}], \tag{2}$$

or, equivalently, by applying the definition of covariance, as[7]

$$1 = E_t[M_{t+1}] \cdot E_t[R_{t+1}] + Cov_t[M_{t+1,}R_{t+1}] \tag{2'}$$

[4] For the 1950–1999 period Reilly et al. (2000) find that return volatility is more stable for stocks than for bonds, the ratio of stock market to bond market volatility is not stable, and the correlation between bond and stock returns varies widely. Jones and Wilson (2004) find similar results for the period 1871–2000.

[5] We limit our study to parametric methods and monthly returns to keep the scope of the analysis manageable and provide a reasonably rich baseline for future study, while supplying results comparable to key findings in the stock literature. The mixed results of studies based on monthly stock return data motivated the exploration of a variety of alternative methodologies to estimate the stock risk-return relation, including the use of daily returns to estimate monthly volatility (see Ghysels, Santa-Clara, & Valkanov, 2005), the use of regime-switching models (see Whitelaw, 2000), and the use of measures of expected rather than realized return (see Jiang & Lee, 2009; Pastor, Sinha, & Swaminathan, 2008).

[6] Eq. (1) can also be derived from the absence of arbitrage. See chapters 2 and 4 of Cochrane (2001) for a detailed discussion of the minimum requirements for Eq. (1) to hold.

[7] By definition, $Cov_t[M_{t+1}, R_{t+1}] = E_t[M_{t+1}R_{t+1}] - E_t[M_{t+1}] \cdot E_t[R_{t+1}]$.

Eq. (2) says that expected *discounted* gross returns always equal one. The expanded expression (2′) introduces the key role that the covariance between an asset's return and the discount factor plays in the risk adjustment of expected return. For a given value of $E_t[M_{t+1}]$, expected gross returns must be inversely related to covariances in any cross-section of assets.

Before discussing the hedging implications of the model in detail, it is useful to examine implications specific to the pricing of default-free bonds. We begin with the gross return to a default-free bond that has a one-period maturity. This risk-free gross return, $R_{f,t}$, is known at time t, so Eq. (2) implies that

$$R_{f,t} = E_t[M_{t+1}]^{-1}. \tag{3}$$

Substituting for future prices in Eq. (1) and using the law of iterated expectations, the price of a τ-period-to-maturity risk-free discount (zero-coupon) bond that pays $1 at maturity is

$$P_{\tau,t} = E_t[M_{t+1,t+\tau}], \tag{4}$$

where $E_t[M_{t+1,t+\tau}] = E_t[M_{t+1}M_{t+2}\ldots M_{t+\tau}]$, and the one-period return to holding the τ-period-to-maturity discount bond is:

$$R_{\tau,t+1} = \frac{P_{\tau,t+1}}{P_{\tau,t}} = \frac{E_{t+1}[M_{t+2,t+\tau}]}{E_t[M_{t+1,t+\tau}]} \tag{5}$$

Eq. (5) shows that the holding period return on a bond is a function of changes in expectations of future values of the stochastic discount factor over the bond's life. Any news or events that cause investors to adjust their expectations of future realizations of the marginal utility of consumption during the bond's life are reflected in bond returns and their volatilities. Since the price of any coupon bond can be expressed as the sum of prices of a series of discount bonds, the intuition behind Eq. (5) holds for coupon bonds as well.

To examine interemporal hedging issues, it is useful to multiply both sides of Eq. (2′) by $E_t[M_{t+1}]^{-1}$, substitute from Eq. (3), and rearrange terms to show that the one-period risk premium to holding *any* asset i is

$$E_t[R_{i,t+1}] - R_{f,t} = -\frac{1}{E_t[M_{t+1}]} Cov_t[M_{t+1}, R_{i,t+1}], \tag{6}$$

where Cov_t is the conditional covariance at time t. According to Eq. (6), an asset will earn a positive risk premium if its realized return is inversely related to M_{t+1}, that is, if the return is high when the marginal utility of consumption is low and low when marginal utility is high. However, a negative risk premium is indicated for hedging assets, that is, assets that have high payoffs when the marginal utility of consumption is high and low payoffs when marginal utility is low. Investors pay more for hedging assets, because hedging assets provide higher payoffs when additional consumption is most desired.

As a point of clarification, it is worth noting that the above definition of a hedging asset differs from that of a "hedge portfolio" as that term is often used in extensions and empirical tests of Merton's ICAPM. In those contexts a hedge portfolio is one that hedges against deteriorations in investment opportunities (decreases in expected future returns) by providing realized returns that are inversely related to expected returns. In the ICAPM, a long position in a hedge portfolio hedges the marginal utility of wealth only if the coefficient of relative risk aversion is greater than one.[8] If risk aversion is less than one, a portfolio that has realized returns that are positively related to shifts in investment opportunities is required to hedge the marginal utility of wealth. The ICAPM specializes the general

[8] The coefficient of relative risk aversion determines whether investors will increase or decrease consumption in response to changes in expected future returns. When risk aversion is greater than one, investors are not aggressive in seeking growth in planned consumption. They increase (decrease) both current and planned future consumption in response to an increase (decrease) in investment opportunities. In the contrary case, when risk aversion is less than one, investors are aggressive in seeking growth in planned consumption. In response to an increase in expected returns, they decrease current consumption to invest more in risky assets. Only in the high risk aversion case does an ICAPM hedging asset (one that provides high realized returns when investment opportunities are poor) do so during periods when the marginal utility of consumption is high.

consumption-based model. The ICAPM is derived with the assumption that the marginal utility of consumption is described by wealth and investment opportunities alone.

Substituting Eq. (5) into Eq. (6) produces the following expression for the excess return to the τ-period discount bond:

$$E_t[R_{\tau,t+1}] - R_{f,t} = -\frac{1}{E[M_{t+1}]} Cov_t \left[M_{t+1}, \frac{E_{t+1}[M_{t+2,t+\tau}]}{E_t[M_{t+1,t+\tau}]} \right]. \tag{7}$$

Eq. (7) demonstrates that the ex ante risk premium on a bond reflects the expected time series properties of M_{t+1} during the bond's maturity. Thus, bonds of adjacent maturities are likely to have similar return characteristics. Characteristics of short and long maturity bonds could be very different.

We follow the convention of using yield spreads as a conditioning variable in our empirical tests. Eq. (4) implies that the gross yield on a τ-period discount bond is

$$Y_{\tau,t} = \left(\frac{1}{P_{\tau,t}}\right)^{1/\tau} = E_t[M_{t+1,t+\tau}]^{-1/\tau}. \tag{8}$$

A comparison of Eq. (7) to Eqs. (3) and (8) shows why a bond's own yield spread contains information that is a useful for predicting bond excess returns.

Using the relationship between correlation and covariance to expand Eq. (6) provides the relation of the ex ante risk premium on *any* asset to that asset's own volatility[9]

$$E_t[R_{i,t+1}] - R_{f,t} = -\frac{vol_t[M_{t+1}]}{E_t\,[M_{t+1}]} vol_t[R_{i,t+1}] corr_t[M_{t+1}, R_{i,t+1}], \tag{9}$$

where vol_t is the conditional standard deviation, the ratio $vol_t[M_{t+1}]/E_t[M_{t+1}]$ is the slope of the mean-variance frontier, and $corr_t$ is the conditional correlation. The correlation summarizes the hedging properties of an asset and determines the sign of the relation between the first and second conditional moments of the asset's excess return. Variation over time in the slope or the correlation will cause the risk–return relation to vary as well.

Summarizing, three main conclusions can be drawn from the general model of asset pricing. First, the sign of the relation between a bond's excess return and conditional volatility depends on the extent to which a long position in the bond serves as an intertemporal hedge against shocks to the marginal utility of consumption. Second, risk–return relations differ across bond maturities. The difference is likely small for adjacent maturity bonds and potentially large for short versus long-term bonds, because the holding period return for each bond depends on changes during the holding period in expected values of the stochastic discount factor over the remaining life of the bond. Third, the relation between bond risk and return may vary over time due to changes in the slope of the mean-variance frontier or changes in the correlation between the asset's return and the stochastic discount factor. In the empirical section of this paper, we focus on documenting the sign of the bond risk–return relation for the full sample period, the consistency of the relation across bond maturities, and the short-term stability of the relation.

4. Data and descriptive statistics

Data are from the *Center for Research in Security Prices* (*CRSP*). Returns are one-month holding period returns. Returns and yields on one-month and three-month to maturity Treasury bills are from the Fama Treasury Bill Term Structure Files. Returns on five Treasury Bond portfolios are from the Fama Maturity Portfolios Returns File with bonds grouped by maturities in one year intervals. Thus, the bond portfolios consist of bonds with maturities of less than 1, 1–2, 2–3, 3–4, and 4–5 years. Only non-callable, non-flower bonds and notes are included in the portfolios. Yields that correspond to the portfolio returns are from the Fama-Bliss Discount Bonds File. Each yield is for the discount bond at the upper bound of maturity allowed in a portfolio. We use returns and yields on the ten-year

[9] By definition, $corr_t[M_{t+1}, R_{i,t+1}] = cov_t[M_{t+1}, R_{i,t+1}]/(vol_t[M_{t+1}]vol_t[R_{i,t+1}])$.

Table 1
Descriptive statistics for Treasury Bond excess returns.

Panel A: Monthly Excess Return ($R_{\tau,t+1} - R_{f,t}$)

Maturity (months)	Mean (×100)	Std. Dev. (×100)	Skewness	Kurtosis	JB	Q(12)	ρ_1	ρ_2	ρ_3	ρ_{12}
$\tau \approx 3$	0.0521	0.0909	2.47	15.39	4357.3***	151.5***	0.32	0.10	0.06	0.02
$0 < \tau \le 12$	0.0658	0.2591	1.49	17.91	5665.1***	79.0***	0.19	−0.04	−0.01	−0.08
$12 < \tau \le 24$	0.1049	0.6489	0.84	15.88	4135.9***	59.4***	0.19	−0.07	−0.05	−0.01
$24 < \tau \le 36$	0.1316	0.9890	0.63	13.47	2726.0***	41.6***	0.14	−0.06	−0.05	0.01
$36 < \tau \le 48$	0.1476	1.2386	0.17	7.87	582.6***	31.7***	0.13	−0.05	−0.05	0.04
$48 < \tau \le 60$	0.1432	1.4523	0.18	6.78	352.6***	30.9***	0.13	−0.07	−0.05	0.04
$\tau \approx 120$	0.1588	2.2266	0.29	4.44	58.8***	15.3	0.06	−0.06	−0.02	0.02
$\tau \approx 240$	0.1814	2.9069	0.38	5.62	182.8***	19.3*	0.04	−0.09	−0.05	−0.01

Panel B: Squared Excess Returns ($R_{\tau,t+1} - R_{f,t})^2$

Maturity (months)	Mean (×100)	Std. Dev. (×100)	Q(12)	ρ_1	ρ_2	ρ_3	ρ_6	ρ_{12}
$\tau \approx 3$	0.0001	0.0004	304.5***	0.52	0.15	0.07	0.10	0.08
$0 < \tau \le 12$	0.0007	0.0029	219.4***	0.36	0.20	0.12	0.18	0.14
$12 < \tau \le 24$	0.0043	0.0166	171.9***	0.19	0.31	0.11	0.23	0.12
$24 < \tau \le 36$	0.0099	0.0351	151.7***	0.14	0.33	0.08	0.22	0.11
$36 < \tau \le 48$	0.0155	0.0406	202.2***	0.17	0.32	0.14	0.26	0.14
$48 < \tau \le 60$	0.0213	0.0511	187.7***	0.13	0.28	0.11	0.28	0.15
$\tau \approx 120$	0.0497	0.0932	160.0***	0.18	0.26	0.14	0.08	0.17
$\tau \approx 240$	0.0847	0.1837	113.2***	0.24	0.21	0.19	0.10	0.10

The time series is from January 1961 to December 2009 with 588 observations. The Jarque–Bera (JB) statistic is a goodness-of-fit measure of the departure of the distribution of a data series from normality, based on the levels of skewness and excess kurtosis. The JB statistic is χ^2 distributed with 2 degrees of freedom. The $Q(12)$ statistic tests for autocorrelation in the first 12 lags. It is χ^2 distributed with 12 degrees of freedom based on the number of lags tested. The autocorrelation coefficient is denoted by ρ_t, where t is the lag, in months. ***, **, * denote significance for the JB or $Q(12)$ test at the 0.01, 0.05, and 0.10 levels, respectively for a one-tailed test.

and twenty-year constant maturity bonds from the *CRSP* Fixed Term Indices Files to represent longer maturity bonds.[10] Where possible, *CRSP* uses a non-callable, non-flower bond in constructing the Fixed Term Indices Files. The sample period is January 1961 to December 2009. We start with January 1961, because there are often substantial gaps in prior months between the desired and available maturities for the ten- and twenty-year constant maturity bonds. Eight excess return series are calculated by subtracting the return to the one-month bill from the holding period returns on the three-month bill, each of the five bond portfolios, and the ten- and twenty-year constant maturity bonds.

We report descriptive statistics for the excess return series in Panel A of Table 1. Both the mean and standard deviation of monthly excess returns tend to increase with maturity, standard deviations rise more sharply. These results are consistent with Pilotte and Sterbenz (2006), who find that bond Sharpe ratios decline with maturity.

The Jarque–Bera (JB) statistics, a goodness-of-fit test of the departure of the distribution of a data series from the normal, reject normality at the 0.01 level for each excess return series. An examination of the skewness and kurtosis of the excess return series indicates that the rejection of normality is due predominately to excess kurtosis relative to the normal distribution. The $Q(12)$ statistics reject the null hypothesis of no autocorrelation in the first 12 lags at the 0.01 level for six of the eight series and at the 0.10 level for one series. Reported autocorrelations indicate that these rejections are due mostly to positive first order autocorrelation in the excess returns. Higher order correlations are close to zero and the pattern of autocorrelations is consistent with stationarity of all of the excess return series.

[10] We use the twenty-year and not the thirty-year bond from the Fixed Term Indices File because there are several years where both series are based on the same bond and the gap between actual and desired maturity is generally smaller for the twenty-year bond. The disadvantage of using constant maturity bonds rather than portfolios is that the realized return is more sensitive to idiosyncratic variation in the price of a single bond.

To examine aspects of the volatility of excess returns, we report descriptive statistics for squared excess returns in Panel B of Table 1. Panel B shows that both the mean and standard deviation of squared excess returns increase with maturity. The $Q(12)$ statistics and autocorrelations reported in Panel B indicate substantial positive autocorrelation in squared excess returns that is more persistent than the positive autocorrelation in excess returns. These statistics suggest the existence of autoregressive conditional heteroskedasticity in each excess return series.

5. Excess return model and model evaluation

In this section we present our empirical model of conditional mean excess returns and carry out diagnostic tests to evaluate the stability of the model. The residuals of this model are used in a later section of this paper to model conditional volatility using predetermined financial conditioning information as instrumental variables.

5.1. Estimating conditional mean excess returns

In order to estimate the conditional volatility of a bond's excess returns, it is useful to isolate the predictable and the unpredictable components of those returns. To do so, we model the conditional mean excess return by regressing excess returns on predetermined conditioning variables. An obvious choice for a conditioning variable is a bond's own yield spread, defined as the beginning of period difference between the bond's yield to maturity and the one-month T-bill rate. The yield spread has been shown to have predictive power for bond excess returns in prior studies by Campbell (1987), Fama (1990), and Pilotte and Sterbenz (2006).[11] Based on the positive first order autocorrelations in excess returns reported in Table 1, we also include the one-month lag of each bond's excess return as a conditioning variable. Thus, our model of excess returns is:

$$R_{\tau,t+1} - R_{f,t} = \alpha_{\tau,0} + \alpha_{\tau,1}(Y_{\tau,t} - R_{f,t}) + \alpha_{\tau,2}(R_{\tau,t} - R_{f,t-1}) + \varepsilon_{\tau,t+1} \quad (10)$$

where t subscripts denote when a variable is observed, $R_{\tau,t+1}$ is the uncertain return from holding from time t to t+1 a bond of maturity τ, $R_{f,t}$ is the risk-free return known at time t and earned by holding a one-month bill from t to t+1, $Y_{\tau,t}$ is the yield-to-maturity observed at time t on a bond of maturity τ, and $\varepsilon_{\tau,t+1}$ is the error term.

Stambaugh (1999) shows that the conventional t-test of return predictability is biased when a regressor is highly persistent and its changes are highly correlated with subsequent returns. Since yield spreads are both highly persistent and their innovations are likely correlated with subsequent returns, we implement the pretest procedure developed by Campbell and Yogo (2005) and Campbell and Yogo (2006) to check on the validity of the t-statistics associated with the yield spreads in our regressions. Results of these pretests (not shown) indicate that the conventional t-test leads to valid inference in all of our regressions of bond excess returns on yield spreads. Because our excess return series are clearly stationary, as indicated by the autocorrelations reported in Table 1, conventional t-tests are valid for the lagged excess returns as well.

The results of ordinary least squares (OLS) estimation of regression Eq. (10) are reported in Table 2. The standard errors are adjusted for autocorrelation and heteroskedasticity. The yield spread is significant at the 0.01 level for three, at the 0.05 level for four, and at the 0.10 level for one of the eight bond maturities. The lagged excess return is significant at the 0.01 level for six bond maturities and the 0.10 level for one maturity. The regression R-square ranges from a low of 0.02 for the twenty-year bond to a high of 0.11 for the three-month bill. These results document predictable variation in bond excess returns for all maturities.

Table 2 also contains test statistics that examine aspects of the regression errors. The JB statistics reject normality of the residuals at the 0.01 level for every regression. The White statistics reject the

[11] Fama (1990) shows that the yield spread contains the market's estimate of the ex ante risk premium and should reflect variation in that premium. The idea that a bond's own term spread contains information that is useful for predicting bond excess returns also is supported by a comparison of our Eq. (7), to Eqs. (3) and (8).

Table 2
Ordinary least squares regressions of excess returns on conditioning variables.

Maturity	Constant	$Y_{\tau,t} - R_{f,t}$	$R_\tau - R_{f,t-1}$	R^2	JB	White-Hetero.	LM-Serial Corr.	LM-ARCH
$\tau \approx 3$	0.000**	0.278***	0.270***	0.11	4300.5***	97.1***	35.6***	112.6***
	(0.000)	(0.210)	(0.090)					
$0 < \tau \leq 12$	0.000	0.5759*	0.245***	0.05	8047.5***	49.4***	64.3***	94.2***
	(0.000)	(0.299)	(0.059)					
$12 < \tau \leq 24$	−0.000	1.178**	0.229***	0.05	5454.4***	10.1**	41.7***	88.4***
	(0.000)	(0.527)	(0.047)					
$24 < \tau \leq 36$	−0.000	1.476**	0.174***	0.04	3572.7***	9.2*	30.0***	85.4***
	(0.001)	(0.728)	(0.043)					
$36 < \tau \leq 48$	−0.001	1.852**	0.158***	0.04	661.2***	22.6***	20.1*	101.2***
	(0.001)	(0.827)	(0.045)					
$48 < \tau \leq 60$	−0.001	1.946***	0.149***	0.03	435.9***	14.3***	19.9*	90.6***
	(0.001)	(0.862)	(0.041)					
$\tau \approx 120$	−0.002	2.617**	0.074*	0.02	48.2***	33.4***	16.1	85.5***
	(0.002)	(1.057)	(0.041)					
$\tau \approx 240$	−0.003*	3.111***	0.038	0.02	215.9***	35.4***	21.9**	58.3***
	(0.002)	(1.115)	(0.045)					

The time series is from January 1961 to December 2009. Regressions of the monthly excess return ($R_{\tau,t+1} - R_{f,t}$) on the beginning-of-period yield spread ($Y_{\tau,t} - R_{f,t}$), and, the one-month lag of the excess return ($R_{\tau,t} - R_{f,t-1}$). The Jarque–Bera (JB) statistic is a goodness-of-fit measure of the departure of the distribution of the regression residuals from normality. The JB statistic is χ^2 distributed with 2 degrees of freedom. The White statistic is a test for heteroskedasticity that is χ^2 distributed with 6 degrees of freedom. The Breusch–Godfrey Lagrange Multiplier (LM-Serial-Corr.) statistic is a test for serial correlation that is χ^2 distributed with 12 degrees of freedom due to the test for serial correlation for up to 12 lags. Engle's Lagrange Multiplier ARCH statistic (LM-ARCH) is a test for ARCH effects in the residuals. It is χ^2 distributed with 12 degrees of freedom due to the test for ARCH effects for 12 lags. Newey–West autocorrelation and heteroskedasticity consistent standard errors are in parentheses. ***, **, * denote significance at 0.01, 0.05, and 0.10 levels, respectively for a two-tailed test; one-tailed test for JB, White, and LM tests.

null hypothesis of no heteroskedasticity at the 0.01 level for six maturities, the 0.05 level for one maturity, and at the 0.10 level for the remaining maturity. The Breusch–Godfrey Lagrange Multiplier statistics reject the null hypothesis of no serial correlation at the 0.01 level in four regressions, at the 0.05 level in one regression, and at the 0.10 level in two regressions. Engle's Lagrange Multiplier ARCH statistics reject the null hypothesis of no autoregressive conditional heteroskedasticity in the residuals at the 0.01 level in every regression. In brief, the regression residuals are non-normally distributed, heteroskedastic, autocorrelated, and show strong evidence of ARCH effects. We consider these aspects of shocks to bond excess returns in the models of the risk–return relation that appear later in this paper.

5.2. *Evaluation of excess return model*

Klemkosky and Pilotte (1992) present evidence of shifts in the stochastic process that generates Treasury Bond risk premiums around October 1979 and October 1982 changes in monetary policy.[12] Thus, we conduct a variety of diagnostic tests to check the specification of our model of excess returns.[13] Due to the large quantity of diagnostic test results, we discuss them but do not report them in tabular form.

Our first set of diagnostic tests is based on recursive least squares estimation of Eq. (10) for each bond maturity. We examine plots against time of the recursive coefficients and two standard error bands around the coefficients for each bond maturity. These plots suggest that the regression coefficients are stable over time. We also apply the CUSUM and CUSUM of squares tests (see Brown, Durbin, & Evans, 1975) that are based on plots against time of the cumulative sums of the recursive residuals and their squared values, respectively. Using the 0.05 significance level, the CUSUM

[12] These dates reflect changes in the Federal Reserve's focus on targeting interest rates and monetary aggregates. Specifically, during 1979–1982 the Fed experimented with using non-borrowed reserves as a target for monetary policy.
[13] Klemkosky and Pilotte (1992) reject the stability of a model of the relation between bond excess returns and short-rate volatility.

tests suggest model stability while the CUSUM of squares tests suggest instability. Overall, the results based on recursive estimation suggest parameter stability but changing variance over the full sample period.

Our second set of diagnostic tests is Wald tests of structural change. Model stability is tested for each bond for each of the five possible monetary regime pairs. The results of tests that assume unequal subperiod variances never reject coefficient stability at the 0.05 level and reject it at the 0.10 level in only one instance. The results of tests that assume equal subperiod variances consistently reject model stability. The Wald test results are consistent with the recursive least squares results in suggesting coefficient stability but changing variance across monetary regimes.

Overall, our specification tests support two conclusions. First, the assumption of coefficient stability over the full sample period is a reasonable one, so our method of estimating conditional mean excess returns appears adequate. Second, the volatility of return shocks varies over time, suggesting that an examination of the relation between excess returns and conditional volatility is well motivated. In the next section, we use models of conditional volatility to examine the relation between bond risk and return.

6. The relation between excess returns and conditional volatility

In this section, we estimate the empirical relation between bond risk and return. Since the method chosen to model conditional volatility is critical to the results of estimating the monthly risk–return relation in the stock literature, we test three specifications of the conditional variance of bond excess returns.[14] We pay special attention to the decision to include or exclude financial conditioning information in the model of conditional variance, because it determines the sign of the estimated risk–return relation for stocks. Our first model estimates conditional variances using predetermined financial conditioning information. Given the strong evidence of ARCH effects in excess returns reported in Table 2, our second model is a simple GARCH-M model. Our third model incorporates both financial conditioning variables and GARCH effects.

6.1. Instrumental variables estimation using financial conditioning information

For each bond maturity, τ, we estimate the following instrumental variables regression:

$$R_{\tau,t+1} - R_{f,t} = \alpha_{\tau,0} + \alpha_{\tau,1}\varepsilon^2 + \mu_{\tau,t+1}, \tag{11}$$

where the $\varepsilon_{\tau,t+1}$ are the residuals from the estimation of Eq. (10) model of excess returns, the slope coefficient $\alpha_{\tau,1}$ is the estimate of the relation between the bond's expected excess return and conditional volatility, and $\mu_{\tau,t+1}$ is the error term. The intercept, $\alpha_{\tau,0}$, provides a check on the empirical specification of the risk–return model, because Eq. (9) indicates that the intercept will equal zero if the model specification is adequate. For instruments we consider lags of the squared residuals, the conditioning variables used to estimate the excess return model, and the one-month Treasury bill return. We include the one-month T-bill rate because of the historically positive relation between interest rate volatility and the level of interest rates, and because of the common use of the short-term interest rate to model volatility in term structure models.[15] An initial examination of the relations between the squared residuals and the candidate instruments indicates that the one-month bill rate and six lags of the squared residuals encompass the candidates that are most useful in modeling conditional volatility. We expect shocks to bond excess returns to be correlated across maturities, so we improve the efficiency of our estimates by choosing an estimation method that takes into account the cross-equation correlations in the error terms. We use the Generalized Method of Moments (GMM) to estimate Eq. (11) simultaneously for all bond maturities. Standard errors are Newey–West heteroskedasticity and autocorrelation consistent.

[14] We repeat each test using the standard deviation and log of conditional variance as the volatility measures. Results for these alternative specifications are discussed in the robustness section that appears later in the paper.

[15] Because of concerns regarding the possible non-stationarity of the one-month rate, we repeat the estimation excluding it from the list of instruments. Results are qualitatively the same.

Table 3
Instrumental variables estimation of risk-return relation for Treasury Bonds.

Maturity	Constant ($\times 10^4$)	Slope	LM-ARCH	LM-Serial Corr.	JB	AR(1) for predicted $\varepsilon^2_{\tau,t+1}$
$\tau \approx 3$	3.350***	284.423***	52.3***	54.3***	17,660.1***	0.881***
	(0.289)	(14.182)				(0.021)
$0 < \tau \leq 12$	5.280***	24.131***	96.7***	55.0***	2451.4***	0.981***
	(0.633)	(3.208)				(0.009)
$12 < \tau \leq 24$	8.010***	8.391***	78.5***	47.1***	3023.1***	0.538***
	(1.670)	(1.270)				(0.051)
$24 < \tau \leq 36$	10.090***	4.857***	75.2***	29.3***	1867.9***	0.553***
	(2.590)	(0.915)				(0.037)
$36 < \tau \leq 48$	11.320***	3.840***	95.1***	24.5***	708.7***	0.714***
	(3.460)	(0.944)				(0.032)
$48 < \tau \leq 60$	13.990***	0.782	85.1***	23.6***	286.6***	0.639***
	(4.350)	(0.994)				(0.035)
$\tau \approx 120$	2.810	3.813***	64.2***	16.1	68.6***	0.953***
	(8.950)	(1.148)				(0.013)
$\tau \approx 240$	17.970*	0.232	49.7***	18.5*	149.2***	0.666***
	(10.330)	(0.800)				(0.034)

Generalized method of moments (GMM) system estimation incorporates the use of instrumental variables and considers the cross-equation correlations in the error terms. The following system of equations is estimated:

$$R_{\tau,t+1} - R_{f,t} = \alpha_{\tau,0} + \alpha_{\tau,1}\varepsilon^2_{\tau,t+1} + \mu_{\tau,t+1},$$

where, τ is the number of months of bond maturity: $\tau \approx 3$, $0 < \tau \leq 12$, $0 < \tau \leq 24$, $0 < \tau \leq 36$, $0 < \tau \leq 48$, $0 < \tau \leq 60$, $\tau \approx 120$, and $\tau \approx 240$, time $t = 1, 588$ represents the beginning of months from January 1961 to December 2009, ε_{t+1} is the residual from the OLS regressions in Table 2, and μ_{t+1} is the error term. The instrumental variables are the one-month return on the one month T-Bill ($R_{f,t}$) and the first six monthly lags of the squared residuals. Engle's Lagrange Multiplier ARCH statistic (LM-ARCH) is a test for ARCH effects in the residuals. It is χ^2 distributed with 12 degrees of freedom due to the test for ARCH effects for 12 lags. The Breusch–Godfrey Lagrange Multiplier (LM-Serial-Corr.) statistic is a test for serial correlation that is χ^2 distributed with 12 degrees of freedom due to the test for serial correlation for up to 12 lags. The Jarque–Bera (JB) statistic is a goodness-of-fit measure of the departure of the distribution of the regression residuals from normality. The JB statistic is χ^2 distributed with 2 degrees of freedom. The AR(1) coefficient is the first order autoregressive coefficient for the fitted values of $\varepsilon^2_{\tau,t+1}$. Newey–West heteroskedasticity and autocorrelation consistent standard errors are in parentheses. ***, **, * denote significance at the 0.01, 0.05, and 0.10 levels respectively; two-tailed test for regression parameters, one-tail test for Q and JB statistics.

Results of the system estimation of Eq. (11) are reported in Table 3. The slope coefficient is significant at the 0.01 level for the 3 month bill, the four bond portfolios of maturities less than or equal to 48 months, and the 120-month bond. The slope coefficient is statistically insignificant for the 48–60-month portfolio and the 240-month bond. Thus, six of our eight maturities produce evidence of a significant positive relation between bond risk and return. In terms of statistical significance, the positive relation tends to be more reliable the shorter the bond maturity.

The intercepts reported in Table 3 are significant at the 0.01 level in six regressions and at the 0.10 level in one regression. The prevalence of significant nonzero intercepts suggests that the IV approach is not adequate for modeling the risk–return relation, as Eq. (9) predicts a zero intercept for a well specified model.

To facilitate comparison of the persistence of the conditional variance estimates across differently parameterized models, we follow Glosten et al. (1993) who regress the conditional variance estimate for each model on a constant and the lagged value of the estimate. These first order autoregressive coefficients are reported for each model that we estimate. For the results of instrumental variables estimation reported in Table 3, the first order autoregressive coefficient is estimated for the predicted values of the $\varepsilon^2_{\tau,t+1}$ from the system estimation of Eq. (11). These AR(1) coefficients indicate that there is substantial persistence in the conditional variance estimates.

The LM-ARCH statistics reported in Table 3 reject, at the 0.01 level, the null hypothesis of no ARCH effects in the first 12 lags of the residuals of each equation. The LM-Serial Correlation and JB statistics are consistent with results reported in Table 2, rejecting the nulls of no auto-correlation and the normality of the residuals. Since GMM requires no distributional assumption, parameter estimates are consistent despite the lack of normally distributed residuals. Because the

IV approach to estimating conditional volatility does a poor job of capturing the ARCH effects in our excess return data, GARCH estimation may provide more accurate estimates of conditional volatility and improve the efficiency of estimates. We use GARCH estimation in the models that follow.

6.2. GARCH-M estimation

A natural way to estimate the relation between bond risk and return is with the following simple GARCH-M model of conditional variance:

$$R_{\tau,t+1} - R_{f,t} = \alpha_{\tau,0} + \alpha_{\tau,1}\sigma^2_{\tau,t+1} + \gamma_{\tau,t+1} \tag{12}$$

$$\sigma^2_{\tau,t+1} = \beta_{\tau,0} + \beta_{\tau,1}\sigma^2_{\tau,t} + \beta_{\tau,2}\gamma^2_{\tau,t} + \upsilon_{\tau,t+1} \tag{13}$$

Estimation is by the method of maximum likelihood. In light of the evidence in Table 1 that excess returns are not normally distributed due to excess kurtosis, we estimate the GARCH-M system assuming that the conditional distribution for the error term is the Generalized Error Distribution (GED). The GED is less restrictive than the normal as it accommodates kurtosis, although it does not accommodate skewness.[16] The GED distribution nests the Student's *t*-distribution and normal distribution.

Table 4 contains the results for GARCH-M estimation. For each maturity, the GED parameter differs significantly from 2, the value for the normal distribution, at either the 0.01 or 0.05 significance levels.[17] The Lagrange Multiplier ARCH statistics indicate that the model is effective at removing most of the ARCH effects from the regression residuals. The coefficient sum, $\beta_{\tau,1} + \beta_{\tau,2}$, is close to one in every variance equation. A sum of one is indicative of the integrated GARCH (IGARCH) process identified by Engle and Bollerslev (1986), which allows for shocks to have a permanent effect on the conditional variance. An IGARCH process is not covariance-stationary but is strictly stationary under conditions identified in Nelson (1990).[18] Similarly, the AR(1) coefficients for the conditional volatility estimates range from 0.93 to 0.97. This confirms the presence of substantial persistence in conditional volatility. The persistence in volatility, as measured by the AR(1) coefficient, is generally greater than that reported in Table 3 for the instrumental variables estimation.

The coefficients on conditional variance in the mean equations are all positive. They are significant at either the 0.01 or 0.05 level for all maturities less than or equal to 60 months and significant at the 0.10 level for the 240-month bond. The risk–return relation is insignificant only for the 120-month bond. Thus, the GARCH-M specification of conditional variance and the IV specification based on financial conditioning information both provide evidence that there is a positive relation between bond risk and return. In terms of statistical significance, both specifications indicate that the positive relation tends to be more reliable the shorter the bond maturity.

Contrary to the case for the IV specification, the intercepts for the GARCH-M regressions generally do not differ significantly from zero. The exceptions are the regressions for the 3-month bill and the portfolio of bonds that are very close (less than 12 months remaining) to maturity. Thus, the GARCH-M approach appears to be a superior model specification.

[16] The GED is a restricted version of the skewed generalized error distribution (SGED). Although it may seem intuitive that a less restrictive distribution is always better, since the non-normality of the error term is not driven by skewness, a loss of efficiency would obtain from over-parameterization of the distribution if specified with the more general SGED.

[17] Although not shown, χ^2 distributed goodness-of-fit log-likelihood ratio tests (one degree of freedom) comparing the fits of the GED and the normal distributions for each maturity indicate that the GED provides a statistically-significantly better fit than the normal.

[18] Nelson shows that an IGARCH(1,1) process with a positive drift is strictly stationary and ergodic. The unconditional density for such a process is the same for all *t*.

Table 4
GARCH-M estimation of risk-return relation for Treasury Bonds.

Maturity	Mean equation		Variance equation			GED parameter	LM-ARCH	Log-L	AR(1) coefficient for $\sigma^2_{\tau,t+1}$
	Constant ($\times 10$)	$\sigma^2_{\tau,t+1}$	Constant ($\times 10^8$)	$\gamma^2_{\tau,t}$	$\sigma^2_{\tau,t}$				
$\tau \approx 3$	0.002***	209.005***	0.511*	0.233***	0.793***	1.145***	11.0	3565.6	0.956***
	(0.000)	(39.148)	(0.267)	(0.044)	(0.027)	(0.092)			(0.012)
$0 < \tau \leq 12$	0.003***	45.948***	6.350*	0.222***	0.786***	1.425***	6.3	2922.2	0.955***
	(0.000)	(12.564)	(2.88)	(0.045)	(0.037)	(0.118)			(0.012)
$12 < \tau \leq 24$	0.002	17.014***	36.000*	0.146***	0.856***	1.436***	19.4*	2294.6	0.968***
	(0.002)	(6.201)	(18.900)	(0.031)	(0.029)	(0.112)			(0.010)
$24 < \tau \leq 36$	0.001	9.768**	57.500*	0.138***	0.871***	1.385***	18.1	2012.8	0.969***
	(0.003)	(4.231)	(31.800)	(0.028)	(0.023)	(0.102)			(0.010)
$36 < \tau \leq 48$	0.001	7.976**	74.200**	0.145***	0.869***	1.382**	14.7	1849.9	0.970***
	(0.004)	(3.564)	(37.600)	(0.030)	(0.023)	(0.102)			(0.010)
$48 < \tau \leq 60$	−0.004	6.965**	88.700**	0.126***	0.886***	1.347***	21.3**	1742.2	0.973***
	(0.005)	(3.150)	(41.600)	(0.026)	(0.020)	(0.101)			(0.010)
$\tau \approx 120$	−0.000	2.485	49.300	0.228***	0.816***	1.486***	11.6	1484.5	0.933***
	(0.006)	(1.907)	(76.800)	(0.046)	(0.030)	(0.106)			(0.015)
$\tau \approx 240$	−0.006	2.736*	216.000	0.123***	0.893**	1.425***	8.3	1322.8	0.968***
	(0.011)	(1.660)	(211.000)	(0.031)	(0.025)	(0.084)			(0.011)

The results below are the GARCH-M regressions for the monthly excess return on the T-Bond ($R_{\tau,t+1} - R_{f,t}$) with conditional variance in the mean equation. The estimated models are:

$$R_{\tau,t+1} - R_{f,t} = \alpha_{\tau,0} + \alpha_{\tau,1}\sigma^2_{\tau,t+1} + \gamma_{\tau,t+1}$$
$$\sigma^2_{\tau,t+1} = \beta_{\tau,0} + \beta_{\tau,1}\sigma^2_{\tau,t} + \beta_{\tau,2}\gamma^2_{\tau,t} + \upsilon_{\tau,t+1}$$

The time series is from January 1961 to December 2009 with 588 observations. The conditional distribution for the error term is the generalized error distribution (GED) to address non-normality of the errors, where the GED parameter (k) is the kurtosis parameter that accommodates fat tails. The GED nests the normal distribution and becomes the normal if k is equal to 2. Engle's Lagrange Multiplier ARCH statistic (LM-ARCH) is a test for ARCH effects in the residuals. It is χ^2 distributed with 12 degrees of freedom due to the test for ARCH effects for 12 lags. Log-L is the value of the log likelihood function. The AR(1) coefficient is the first order autoregressive coefficient for the fitted values of $\sigma^2_{\tau,t+1}$. Standard errors are in parentheses. ***, **, * denote significance at the 0.01, 0.05 and 0.10 levels, respectively; two-tailed test for regression and GED parameters, one-tailed test for LM-ARCH.

6.3. GARCH-M estimation with financial conditioning information

Our third model of conditional volatility incorporates both financial conditioning variables and GARCH effects:

$$R_{\tau,t+1} - R_{f,t} = \alpha_{\tau,0} + \alpha_{\tau,1}\sigma^2_{\tau,t+1} + \gamma_{\tau,t+1} \quad (14)$$

$$\sigma^2_{\tau,t+1} = \beta_{\tau,0} + \beta_{\tau,1}\sigma^2_{\tau,t} + \beta_{\tau,2}\gamma^2_{\tau,t} + \beta_{\tau,3}R_{f,t} + \beta_{\tau,4}(Y_{\tau,t} - R_{f,t}) + \beta_{\tau,5}(R_{\tau,t} - R_{f,t-1}) + \upsilon_{\tau,t+1} \quad (15)$$

Results, reported in Table 5, indicate that incorporating both financial conditioning variables and GARCH effects in the model of conditional variance provides stronger evidence of a positive relation between bond risk and return than does the simple GARCH-M estimation of Table 4. In the mean equation, the coefficient on the variance term is positive and significant at the 0.01 level for four bond maturities and at the 0.05 level for three bond maturities. Moreover, as is the case for the simple GARCH-M regressions, the intercepts for the GARCH-M regressions that incorporate financial conditioning variables in the variance equation generally do not differ significantly from zero. The model seems well specified for all but the shortest-term bonds.

An examination of the results for the variance equation indicates that the one-month rate is significant (0.05 level or lower) in explaining the conditional variance of every bond maturity. The significance of the yield spread (0.01 level) in explaining conditional variance is limited to the 3-month bill. The lagged excess return is significant (0.05 level) only for the 120-month bond.

In Table 5, the GED parameters differ significantly from the value for the normal distribution (0.01 level) in every regression. The Lagrange Multiplier ARCH statistics indicate that the model is effective at removing most of the ARCH effects from the regression residuals. For each maturity, the inclusion of financial conditioning information in the variance equation increases the value of the log-likelihood function relative to the value reported in Table 4 for simple GARCH-M estimation. The persistence in conditional volatility, as measured by the AR(1) coefficient, is usually close to that reported in Table 4 for the simple GARCH model.

6.4. Additional robustness tests

As a robustness check, all three models are estimated using the conditional standard deviation and the log of conditional variance rather than the conditional variance to estimate the risk–return relation. While these changes do not materially alter our conclusions, there are systematic effects on the *p*-values for the coefficient on the conditional volatility measure. For instrumental variables estimation using financial conditioning information, using the conditional standard deviation tends to raise *p*-values slightly. For GARCH-M estimation, both with and without conditioning variables, using the conditional standard deviation tends to lower *p*-values slightly. The preponderance of results remains consistent with a positive risk–return relation.

We also check the robustness of our results to the use of asymmetric GARCH-M models that allow positive and negative shocks to returns to have different impacts on the conditional volatility. Contrary to the existing evidence for stocks, for which asymmetries are significant determinants of conditional volatility that cause the sign of the risk–return relation to reverse, we find that these asymmetries are insignificant in determining the conditional volatilities of bonds.

We also explore the use of alternatives to the GED distribution for estimating GARCH models when regression residuals are not conditionally normally distributed. We repeat estimation of all GARCH models using the Student's *t*-distribution and using the quasi-maximum likelihood method of Bollerslev and Wooldridge (1992). Our conclusions are robust to these changes in the specification of the conditional distribution for errors.

We use GMM system estimation of Eq. (11) to produce our estimates of the risk–return relation that are based on modeling the conditional variance using only financial conditioning information. Advantages of the GMM estimator are that it takes into account the cross-equation correlations in the error terms and is robust to heteroskedasticity and autocorrelation of unknown form. As a check on the importance of these advantages we also estimate Eq. (11) using three-stage least squares (3SLS) and single-equation estimation. 3SLS accounts for the cross-equation correlations in the error term and

Table 5
GARCH-M estimation of risk-return relation with variance conditioning variables.

Maturity	Mean equation		Variance equation						GED parameter	LM-ARCH	Log-L	AR(1) coefficient for $\sigma^2_{\tau,t+1}$
	Constant ($\times 10^4$)	$\sigma^2_{\tau,t+1}$	Constant ($\times 10^6$)	$\sigma^2_{\tau,t}$	$\gamma^2_{\tau,t}$	$R_{f,t}$ ($\times 10^4$)	$Y_{\tau,t} - R_{f,t}$ ($\times 10^4$)	$R_\tau - R_{f,t-1}$ ($\times 10^4$)				
$\tau \approx 3$	1.000***	719.158***	−0.018***	0.410***	0.161***	0.240***	1.490***	1.290***	1.100***	27.9***	3592.7	0.818***
	(0.150)	(91.756)	(0.004)	(0.062)	(0.029)	(0.044)	(0.541)	(0.347)	(0.077)			(0.024)
$0 < \tau \le 12$	2.510***	59.944***	−0.049	0.780***	0.182***	0.434***	0.562	0.255	1.464***	10.3	2928.1	0.957***
	(0.560)	(14.197)	(0.038)	(0.040)	(0.041)	(0.157)	(0.693)	(0.610)	(0.126)			(0.012)
$12 < \tau \le 24$	1.500	21.271***	0.700*	0.871***	0.104***	3.750***	0.824	0.729	1.472***	22.3**	2301.3	0.962***
	(1.940)	(6.865)	(0.412)	(0.028)	(0.025)	(1.240)	(3.250)	(1.380)	(0.123)			(0.009)
$24 < \tau \le 36$	0.181	12.264***	−2.910**	0.877***	0.102***	11.750***	4.470	1.740	1.446***	17.3	2020.8	0.975***
	(3.000)	(2.717)	(1.270)	(0.028)	(0.025)	(4.030)	(6.760)	(2.380)	(0.116)			(0.009)
$36 < \tau \le 48$	−0.298	8.404**	−4.680**	0.889***	0.105***	17.730**	3.940	−2.940	1.491***	9.7	1860.8	0.982***
	(3.280)	(3.451)	(2.350)	(0.028)	(0.027)	(7.180)	(11.820)	(2.570)	(0.129)			(0.008)
$48 < \tau \le 60$	−4.820	6.964**	−7.150*	0.904***	0.092***	25.650**	3.840	−3.100	1.447***	19.8*	1753.5	0.984***
	(3.700)	(2.938)	(3.970)	(0.027)	(0.024)	(11.510)	(18.570)	(3.250)	(0.123)			(0.007)
$\tau \approx 120$	−3.970	2.774	−23.100**	0.852***	0.146***	72.36**	51.31	−10.100**	1.574***	15.5	1495.7	0.963***
	(4.500)	(1.917)	(11.500)	(0.038)	(0.036)	(31.490)	(48.87)	(5.310)	(0.115)			(0.011)
$\tau \approx 240$	−11.140	3.061**	−42.600*	0.871***	0.112***	129.590**	137.51	−11.450	1.459***	9.3	1328.9	0.968***
	(9.53)	(1.605)	(23.200)	(0.041)	(0.033)	(70.100)	(93.12)	(8.110)	(0.088)			(0.010)

The following GARCH–M models are estimated:

$$R_{\tau,t+1} - R_{f,t} = \alpha_{\tau,0} + \alpha_{\tau,1}\sigma^2_{\tau,t+1} + \gamma_{\tau,t+1}$$
$$\sigma^2_{\tau,t+1} = \beta_{\tau,0} + \beta_{\tau,1}\sigma^2_{\tau,t} + \beta_{\tau,2}\gamma^2_{\tau,t} + \beta_{\tau,3}R_{f,t} + \beta_{\tau,4}(Y_{\tau,t} - R_{f,t}) + \beta_{\tau,5}(R_{\tau,t} - R_{f,t-1}) + \upsilon_{\tau,t+1}$$

The time series is from January 1961 to December 2009 with 588 observations. These regression models estimate the relation between the excess return ($R_{\tau,t+1} - R_{f,t}$) and its conditional variance, where the conditioning variables include the beginning of period monthly return on the 1-month T-Bill ($R_{f,t}$), the beginning of period yield spread ($Y_{\tau,t} - R_{f,t}$), and the one-month lag of excess return ($R_{\tau,t} - R_{f,t-1}$). The conditional distribution for the error term is the generalized error distribution (GED) to address non-normality of the errors, where the GED parameter (k) is the kurtosis parameter that accommodates fat tails. The GED nests the normal distribution and becomes the normal if $k = 2$. Engle's Lagrange Multiplier ARCH statistic (LM-ARCH) is a test for ARCH effects in the residuals. It is χ^2 distributed with 12 degrees of freedom due to the test for ARCH effects for 12 lags. Log-L is the value of the log likelihood function. AR(1) is the first order autoregressive coefficient for the fitted values of $\sigma^2_{\tau,t+1}$. Standard errors are in parentheses. ***, **, * denote significance at the 0.01, 0.05 and 0.10 levels, respectively. The regression and GED parameters are two-tailed tests. The LM-ARCH is a one-tail test.

heteroskedasticity, but does not account for autocorrelation in the errors. Single-equation estimation accounts for heteroskedasticity and autocorrelation of unknown form, but not the cross-equation correlations in the error terms. Results for 3SLS are similar, but slightly weaker than GMM estimation. Results for single-equation estimation are substantially weaker than both 3SLS and GMM estimation. Thus, accounting for the cross-equation correlations in the errors produces efficiency gains that have an important impact on the statistical significance of the estimated relation between bond risk and return.

6.5. Discussion of implications for asset pricing models

Our findings have implications for the modeling of investor preferences and asset returns that support the conclusions of Cochrane (2001, 2006). Our finding of a positive relation between the first two moments of bond returns is evidence that bond realized returns tend to be high during good times of low marginal utility and low during bad times of high marginal utility. The inverse relation between a fixed income security's price and discount rate, implies the opposite relation for expected bond returns and marginal utility. Thus, a challenge for asset-pricing models is to capture the fact that investors associate periods of high expected (low realized) bond returns with bad times. A well known result from the prediction literature is that expected returns on stocks and bonds are higher near the troughs of recessions than at the peaks.[19] Thus, our results support Cochrane's conclusion that theoretical models need to explain, and empirical models need to capture, the fact that investors fear recessions.

The existing ICAPM specializations of the consumption-based model are ill-suited to explain our results.[20] The ICAPM approach assumes that the marginal utility of consumption is a function only of wealth and state variables that describe the conditional distribution of expected future returns. Unless the coefficient of relative risk aversion is very low (less than one), the ICAPM associates good times with high, and bad times with low, expected returns.[21] If one believes that risk aversion is reasonably high, our results support the conclusion that investor preferences are not adequately modeled by wealth and investment opportunities alone.

Our results are consistent with Cochrane's (2001, 2006) conclusion that asset pricing models must capture the fact that investors are concerned not only with the wealth effects of holding assets, but of the fact that assets do poorly at particular times or in particular states of nature (recessions). Cochrane suggests that this can be done in a utility framework by adding arguments into the utility function that enter nonseparably either over time or over states of nature. For example, Campbell and Cochrane (1999) associate high expected returns with bad times by adding an argument, habit, that enters the utility function nonseparably over time. For the ICAPM framework, Cochrane recommends adding a recession state variable to the value function.

7. Stability of the risk–return relation

The regression models reported in Tables 3–5 assume a time invariant linear relation between the expected excess return and conditional variance. The theoretical model of Section II does not restrict

[19] Fama and French (1989) find that risk premiums on stocks and long-term corporate bonds are related to variables that track business conditions. They conclude that excess returns are high when economic conditions are weak and low when economic conditions are strong. Pilotte and Sterbenz (2006) report similar findings for Treasury bonds and stocks. They find that conditional mean excess returns on Treasury bond portfolios of maturities of one to five years peak near the troughs of recessions, while conditional means of shorter maturity bonds and bills peak during recessions prior to the trough (see their Table 5).

[20] Two excellent sources of discussion of the relation of the ICAPM to the general model are Cochrane (2006, 2007).

[21] The coefficient of relative risk aversion determines whether investors will increase or decrease consumption in response to changes in expected future returns. When risk aversion is greater than one, investors increase both current and planned future consumption in response to an increase in expected returns. When risk aversion is less than one, investors are more aggressive in seeking growth in planned consumption. In response to an increase in expected returns, they decrease current consumption to invest more in risky assets.

the risk–return relation to a stable linear relation. In this section, we evaluate the linearity and stability of the relation between bond risk and return.

7.1. Analysis of excess return model residuals

A straightforward way to check the linear restriction for any of our models is to examine the relation between the regression error and financial conditioning information. If conditioning information explains variability in excess returns that is not related to conditional volatility, a linear relation between the conditional mean and conditional variance is rejected. Such a finding suggests that the reward to volatility changes over time.

Table 6 reports the results of OLS regressions of residuals from our models on financial conditioning information. For all three models, conditioning variables have explanatory power beyond that of the conditional variance. The explanatory power is greatest for the model where the conditional variance is based only on financial conditioning information. The explanatory power is lower in models where the conditional variance estimates incorporate GARCH effects. At least one conditioning variable is significant in most of the residual regressions. Clearly, the conditioning variables capture variation in excess returns that is not related to our estimates of the conditional variance. A time invariant linear specification of the relation between the conditional mean and conditional volatility is rejected, which suggests that the reward to volatility changes over time.[22,23]

7.2. Rolling correlations between conditional means and conditional variances

To provide evidence on the impact of changing reward to volatility on the stability of the risk–return relation we examine the relation between estimates of the conditional mean and conditional variance. We calculate contemporaneous correlations between estimates of conditional means and conditional variances for each bond maturity over 17-month rolling periods.[24]

To get a time series of fitted values, we estimate final models of conditional means and variances for Treasury Bond excess returns. Our final model incorporates all aspects of our prior models. The conditional mean is modeled as a function of both the conditional variance and financial conditioning information. The conditional variance incorporates both GARCH effects and financial conditioning information. We first estimate the following GARCH-M model:

$$R_{\tau,t+1} - R_{f,t} = \alpha_{\tau,0} + \alpha_{\tau,1}\sigma^2_{\tau,t+1} + \alpha_{\tau,2}(Y_{\tau,t} - R_{f,t}) + \alpha_{\tau,3}(R_{\tau,t} - R_{f,t-1}) + \gamma_{\tau,t+1} \tag{16}$$

$$\sigma^2_{\tau,t+1} = \beta_{\tau,0} + \beta_{\tau,1}\sigma^2_{\tau,t} + \beta_{\tau,2}\gamma^2_{\tau,t} + \beta_{\tau,3}R_{f,t} + \beta_{\tau,4}(Y_{\tau,t} - R_{f,t}) + \beta_{\tau,5}(R_{\tau,t} - R_{f,t-1}) + \upsilon_{\tau,t+1} \tag{17}$$

After the initial estimation, we drop explanatory variables that are not significant at the 0.10 level and re-estimate the model. The final models with only variables that are statistically significant in explaining the conditional mean or conditional variance are reported in Table 7.

An interesting aspect of Table 7 is that the GARCH in mean term is significant for only two bond maturities. Results of omitted variable tests (not reported) confirm this conclusion. The effect of the conditional variance on the conditional mean is generally subsumed by the financial conditioning information. The yield spread is always significant in explaining the excess return and the lagged excess return is significant in explaining the excess return for all but the 240-month bond. In the variance equation, the GARCH terms and the one-month rate are always significant in explaining the

[22] Pilotte and Sterbenz (2006) find that Sharpe ratios on long-term bonds, but not short-term bonds, vary over the business cycle. Our results differ in indicating that there is time variation in the reward to volatility for all bond maturities. A potential explanation for the difference in results is that our tests are not tied to the business cycle.

[23] The results for bonds reported in Table 7 are consistent with results that Harvey (2001) reports for stocks. Harvey finds that the rejection of a linear risk-return relation for stocks is robust to changes in the method used to estimate the conditional variance. He also presents graphic evidence that the ratio of conditional mean to conditional volatility for stocks has a distinct business cycle pattern.

[24] In his examination of the stability of the risk-return relation for common stocks, Whitelaw (1994) chooses a 17-month window to balance the need for reasonably accurate estimates with the need for a period that is short enough to pick up variation over the length of a business cycle. We follow his approach to facilitate a comparison with existing results for stocks.

Table 6
Analysis of residuals from models of the bond risk-return relation.

Maturity	Residuals from risk-return model with conditional volatility estimates based on financial conditioning information				Residuals from risk-return model with conditional volatility estimates based on Simple GARCH-M model				Residuals from risk-return model with conditional volatility estimates based on GARCH-M with financial conditioning information in the variance equation			
	Constant ($\times 10^4$)	$Y_{\tau,t} - R_{f,t}$	$R_\tau - R_{f,t-1}$	R^2	Constant ($\times 10^4$)	$Y_{\tau,t} - R_{f,t}$	$R_\tau - R_{f,t-1}$	R^2	Constant ($\times 10^4$)	$Y_{\tau,t} - R_{f,t}$	$R_\tau - R_{f,t-1}$	R^2
$\tau \approx 3$	−2.720***	0.686***	0.082	0.12	−1.260***	0.653***	0.089	0.10	−1.090**	0.582***	0.052	0.06
	(0.382)	(0.144)	(0.078)		(0.471)	(0.218)	(0.064)		(0.481)	(0.199)	(0.063)	
$0 < \tau \le 12$	6.640***	−1.261***	0.167**	0.16	9.090***	−1.559***	0.153***	0.19	8.950***	−1.570***	0.152**	0.19
	(2.040)	(0.356)	(0.079)		(0.280)	(0.464)	(0.066)		(1.380)	(0.145)	(0.067)	
$12 < \tau \le 24$	14.910***	−2.180***	0.177***	0.11	19.290***	−2.574***	0.164***	0.12	19.180***	−2.613***	0.162***	0.13
	(5.210)	(0.675)	(0.054)		(7.040)	(0.864)	(0.046)		(7.070)	(0.863)	(0.046)	
$24 < \tau \le 36$	20.090**	−2.450***	0.141***	0.07	26.680**	−2.878***	0.135***	0.08	26.330**	−2.924***	0.132***	0.08
	(8.030)	(0.834)	(0.048)		(10.470)	(1.050)	(0.042)		(10.500)	(1.048)	(0.041)	
$36 < \tau \le 48$	20.110**	−2.258***	0.134***	0.05	25.470**	−2.594***	0.131***	0.06	26.320**	−2.592***	0.133***	0.06
	(9.690)	(0.850)	(0.045)		(11.200)	(0.968)	(0.043)		(11.330)	(0.970)	(0.043)	
$48 < \tau \le 60$	22.450*	−2.218**	0.135***	0.04	28.070**	−2.443**	0.129***	0.04	28.240**	−2.418**	0.131***	0.04
	(12.590)	(0.997)	(0.042)		(13.000)	(1.023)	(0.040)		(13.100)	(1.023)	(0.040)	
$\tau \approx 120$	17.310	−1.811*	0.056	0.01	26.550*	−2.056***	0.060	0.01	28.950*	−2.002***	0.063	0.01
	(14.190)	(0.937)	(0.038)		(15.170)	(1.008)	(0.039)		(15.310)	(10.14)	(0.039)	
$\tau \approx 240$	8.510	−0.750	0.038	0.00	14.250	−1.180	0.035	0.00	16.030	−1.147	0.037	0.00
	(19.130)	(1.130)	(0.044)		(19.250)	(1.160)	(0.044)		(19.280)	(1.154)	(0.044)	

Residuals are from the excess return regressions reported in Tables 3–5, where the conditional volatility is modeled using financial conditioning information in Table 3 a simple GARCH-M model in Table 4 and a GARCH-M model with financial conditioning information included in the conditional variance equation in Table 5 The residuals from each model of the risk-return relation are regressed on the beginning-of-period yield spread ($Y_{\tau,t} - R_{f,t}$), and, the one-month lag of the excess return ($R_{\tau,t} - R_{f,t-1}$). Results are for OLS estimation with Newey–West autocorrelation and heteroskedasticity consistent standard errors reported in parentheses. ***, **, * denote significance at the 0.01, 0.05, and 0.10 levels, respectively.

Table 7
Final models of conditional means and conditional variances for Treasury Bond returns.

Maturity	Mean equation				Variance equation					GED Parameter	LM-ARCH	Log-L	AR(1) coefficient for $\sigma^2_{\tau,t+1}$
	Constant ($\times 10^4$)	$\sigma^2_{\tau,t+1}$	$Y_{\tau,t}-R_{f,t}$	$R_\tau - R_{f,t-1}$	Constant ($\times 10^6$)	$\sigma^2_{\tau,t+1}$	$\varepsilon^2_{\tau,t-1}$	$R_{f,t}$ ($\times 10^4$)	$R_\tau - R_{f,t-1}$ ($\times 10^4$)				
$\tau \approx 3$	1.070***	223.91***	0.298***	0.192***	0.003	0.832***	0.131***	0.081***	0.401**	1.139***	15.6	3607.3	0.965***
	(0.188)	(60.45)	(0.071)	(0.040)	(0.002)	(0.026)	(0.031)	(0.013)	(0.172)	(0.094)			(0.011)
$0 < \tau \le 12$	0.007	42.240***	0.447***	0.200***	0.034	0.812***	0.163***	0.390***		1.408***	14.9	2943.0	0.954***
	(0.784)	(16.17)	(0.103)	(0.042)	(0.029)	(0.035)	(0.036)	(0.140)		(0.124)			(0.012)
$12 < \tau \le 24$	−2.780		1.0281***	0.204***	−0.618***	0.889***	0.096***	3.150***		1.361***	29.1***	2313.5	0.971***
	(2.310)		(0.254)	(0.041)	(0.229)	(0.024)	(0.024)	(0.784)		(0.112)			(0.010)
$24 < \tau \le 36$	−6.470*		1.582***	0.158***	−2.270***	0.897***	0.094***	9.340***		1.348***	17.6	2031.4	0.974***
	(3.530)		(0.359)	(0.040)	(0.487)	(0.022)	(0.024)	(1.850)		(0.110)			(0.009)
$36 < \tau \le 48$	−9.900**		1.825***	0.131***	−4.680***	0.889***	0.100***	18.770***		1.435***	11.3	1868.7	0.978***
	(4.620)		(0.438)	(0.040)	(0.855)	(0.024)	(0.026)	(3.330)		(0.125)			(0.009)
$48 < \tau \le 60$	−14.900***		2.002***	0.138***	−7.910***	0.895***	0.094***	30.070***		1.375***	16.3	1763.0	0.980***
	(4.950)		(0.475)	(0.039)	(1.490)	(0.023)	(0.026)	(5.470)		(0.117)			(0.008)
$\tau \approx 120$	−17.790***		2.021***	0.097**	−12.400***	0.882***	0.125***	45.080***	−7.260*	1.551***	14.8	1501.1	0.973***
	(6.460)		(0.611)	(0.039)	(3.21)	(0.025)	(0.028)	(13.370)	(4.390)	(0.118)			(0.009)
$\tau \approx 240$	−30.650***		3.447***		−17.600**	0.893***	0.109***	70.520***		1.392***	10.1	1334.5	0.970***
	(10.620)		(0.734)		(6.920)	0.027	0.030	(26.530)		(0.091)			(0.010)

The initial estimated models are:

$$R_{\tau,t+1} - R_{f,t} = \alpha_{\tau,0} + \alpha_{\tau,1}\sigma^2_{\tau,t+1} + \alpha_{\tau,2}(Y_{\tau,t} - R_{f,t-1}) + \alpha_{\tau,3}(R_{\tau,t} - R_{f,t-1}) + \gamma_{\tau,t+1}$$
$$\sigma^2_{\tau,t+1} = \beta_{\tau,0} + \beta_{\tau,1}\sigma^2_{\tau,t} + \beta_{\tau,2}\gamma^2_{\tau,t} + \beta_{\tau,3}R_{f,t} + \beta_{\tau,4}(Y_{\tau,t} - R_{f,t}) + \beta_{\tau,5}(R_{\tau,t} - R_{f,t-1}) + \upsilon_{\tau,t+1}$$

The time series is from January 1961 to December 2009 with 588 observations. The insignificant explanatory variables were dropped to obtain the final estimated models reported below. The initial regression models include the conditional variance in the mean equation, and the mean and variance equations initially includes the beginning of period yield spread ($Y_{\tau,t} - R_{f,t}$), and the one-month lag of excess return ($R_{\tau,t} - R_{f,t-1}$) as conditioning variables. The conditional variance also includes the beginning of period monthly return on the 1-month T-Bill ($R_{f,t}$). The conditional distribution for the error term for the estimations is the generalized error distribution (GED) to address non-normality of the errors. The GED parameter (k) is the kurtosis parameter that accommodates fat tails and becomes the normal distribution if $k = 2$. Engle's Lagrange Multiplier ARCH statistic (LM-ARCH) is a test for ARCH effects in the residuals. It is distributed with 12 degrees of freedom due to the test for ARCH effects for 12 lags. Log-L is the value of the log likelihood function. AR(1) is the first order coefficient for the fitted values of $\sigma^2_{\tau,t+1}$. Standard errors are in parentheses. ***, **, *denote significance at the 0.01, 0.05, and 0.10 levels, respectively. The regression and GED parameters are two-tailed tests. The LM-ARCH is a one-tail test.

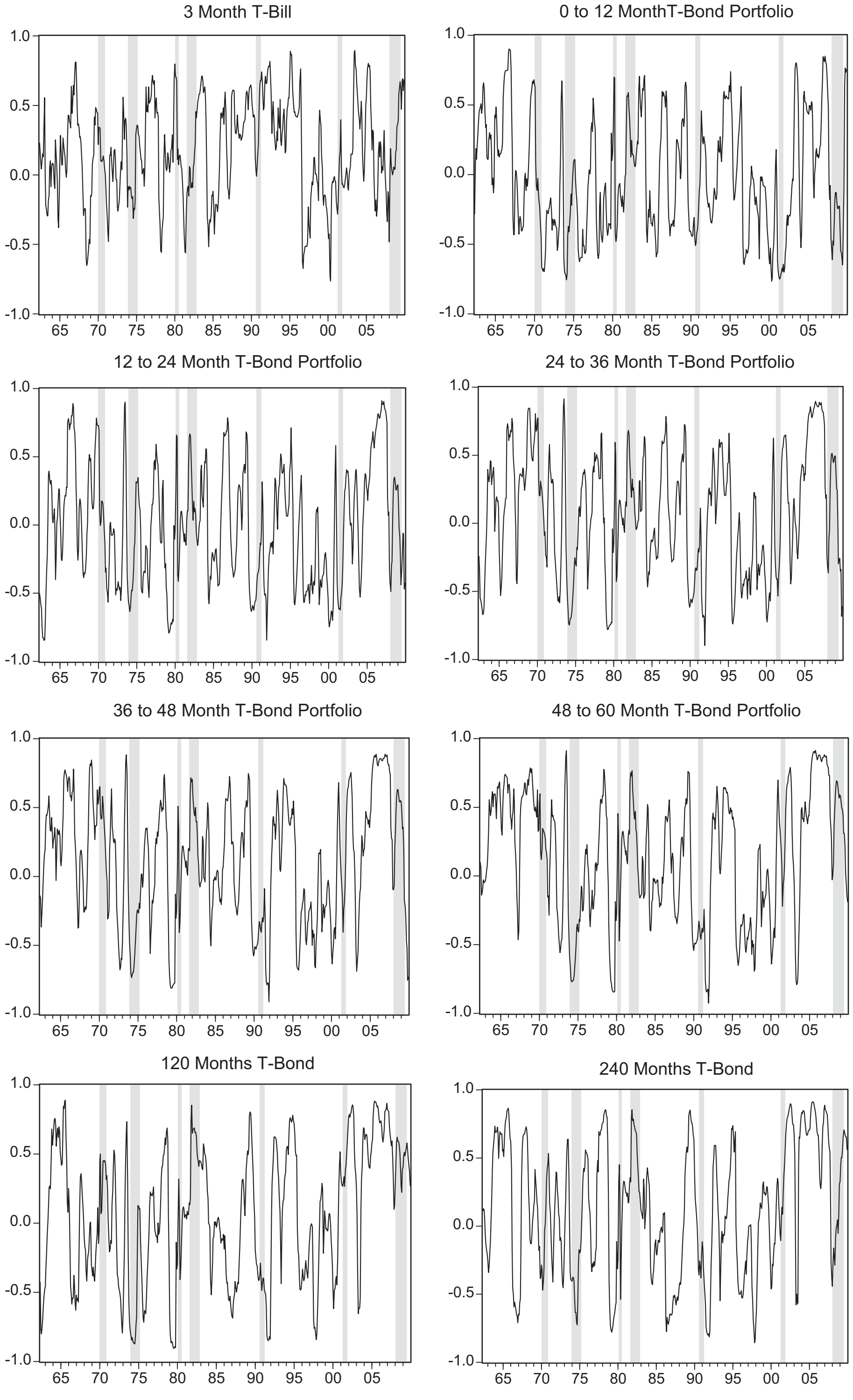
3 Month T-Bill
0 to 12 MonthT-Bond Portfolio
12 to 24 Month T-Bond Portfolio
24 to 36 Month T-Bond Portfolio
36 to 48 Month T-Bond Portfolio
48 to 60 Month T-Bond Portfolio
120 Months T-Bond
240 Months T-Bond

Table 8
Correlation matrix of rolling estimates of correlations between the conditional moments of bond excess returns.

Maturity	$\tau \approx 3$	$0 < \tau \le 12$	$12 < \tau \le 24$	$24 < \tau \le 36$	$36 < \tau \le 48$	$48 < \tau \le 60$	$\tau \approx 120$	$\tau \approx 240$
$\tau \approx 3$	1.00							
$0 < \tau \le 12$	0.47	1.00						
$12 < \tau \le 24$	0.26	0.70	1.00					
$24 < \tau \le 36$	0.12	0.50	0.89	1.00				
$36 < \tau \le 48$	0.03	0.44	0.79	0.91	1.00			
$48 < \tau \le 60$	−0.02	0.35	0.70	0.87	0.93	1.00		
$\tau \approx 120$	0.11	0.22	0.46	0.55	0.67	0.74	1.00	
$\tau \approx 240$	0.03	0.13	0.31	0.47	0.54	0.67	0.79	1.00

The following are correlations between rolling estimates of correlations between the fitted values of the conditional mean and conditional variance of excess returns on bonds of different maturities. The 17-month rolling correlation for each bond maturity is between the conditional excess return and conditional variance as shown in Fig. 1. The model used to estimate the conditional excess returns and variances is shown in Table 7 for each maturity. Using all of the time series from January 1961 to December 2009, the correlation coefficients begin in May 1962 and end in December 2009.

conditional volatility. The yield spread is never significant in the variance equation and the lagged excess return is significant only for the 3-month bill and 120 month bond. Viewed overall, the results reported in Table 7 indicate that the yield spread and lagged excess return are generally important in predicting conditional means, while the one-month rate and GARCH effects are important in predicting the conditional variances.

Fig. 1 presents graphs of the rolling estimates of correlations between the fitted series of conditional excess returns and conditional variances for each bond maturity. The graphs show substantial variation over time in the short-term relation between bond risk and return. For longer maturities, both the range of correlations and incidence of negative correlations are similar to those reported by Whitelaw (1994) for stocks. For the shortest maturities, the range of correlations is diminished somewhat, but there remains substantial variation over time and numerous negative correlations.

The graphs in Fig. 1 are shaded to show business cycle expansions and contractions. The correlations vary substantially within both expansions and contractions. The graphs show no obvious business cycle pattern in the relation between bond risk and return, though there appears to be some tendency for the estimated relation to decrease either prior to or early in recessions. Our ability to draw firm conclusions regarding business cycle patterns is limited by the fact that our sample contains only seven measured contractions.

To illustrate the co-movement in the risk–return relation across bond maturities, in Table 8 we report correlations between the rolling correlations of each maturity pair. The correlations in Table 8 indicate that time variation in the risk–return relation is similar for adjacent maturities, but differs substantially when the difference in maturity is large. Nevertheless, correlations are positive for all but one pair of bond maturities.

Overall, our examination of rolling correlations shows instability in the short-term relation between bond risk and return. The relation is often negative for each bond maturity. For longer maturities, both the range of correlations and incidence of negative correlations are similar to those reported previously for common stocks. For shorter maturities the range is diminished somewhat; however, the rolling correlations for all bond maturities do tend to move together. Negative rolling correlations suggest there may be specific time periods in which bonds were effective hedging assets. Further study is required to draw any definitive conclusions regarding this possibility.

Fig. 1. Rolling estimates of correlations between the conditional moments of bond excess returns The graphs above plot the 17-month rolling estimates of the correlation between the fitted values of the conditional mean excess return and conditional variance for each bond maturity. The models used to predict the excess returns and variances are reported in Table 7. Using all of the time series from January 1961 to December 2009, the correlation coefficients begin in May 1962 and end in December 2009. Shaded areas represent business cycle contractions as defined by the National Bureau of Economic Research with the beginning month defined as the first trough month and the ending month defined as the last trough month. Non-shaded areas are business cycle expansions.

8. Conclusions

Our full sample estimation of the linear relation between the conditional mean and conditional volatility of U.S. Treasury Bonds documents a significant positive relation between bond risk and return for maturities of 3 months to 20 years. This finding is not very sensitive to the method used to estimate conditional volatility and is especially reliable for bond maturities of 5 years or less. A positive, rather than negative, risk–return relation indicates that Treasury Bonds are not a hedging asset as that concept is defined in consumption-based models of intertemporal choice. Rather, an effective hedging asset has the return characteristics of a short position in Treasury Bonds. Short positions on shorter-maturity bonds appear to be the most statistically reliable means for an investor to hedge the marginal utility of consumption.

Our full sample results are consistent with the conclusion that realized returns on Treasury Bonds are high when investors least value, and low when investors most value, the benefits of an additional dollar of consumption. Thus, for a special case of the consumption-based model to accurately reflect investor preferences, it must explain why investors associate bad times of high marginal utility with periods of low realized and high expected bond returns. Special cases that assume that the marginal utility of consumption is a function of at most wealth and investment opportunities, such as the ICAPM specializations of Merton (1973) and Campbell (1993), do not do so. Unless one assumes that risk aversion is very low, those models associate bad times with low expected returns. Explaining why investors associate bad times with high expected returns requires a model that captures the fact that investors are concerned not only with the wealth effects of holding assets, but with the fact that assets do poorly at particular times or in particular states of nature (recessions). Campbell and Cochrane (1999) do so by adding an argument to the utility function, habit that enters nonseparably over time.

Our analysis of the linearity and stability of the risk–return relation produces evidence that the reward to volatility and the short-term relation between bond risk and return may vary over time. The fact that rolling correlations between estimates of the conditional mean and conditional volatility are often negative suggests that there may be specific time periods in which bonds were effective hedging assets. Further study is required to draw any definitive conclusions regarding this possibility.

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Empirical analysis of the generalized consumption asset pricing model: Estimating the cost of capital

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ABSTRACT

Other than the problematic discounted cash flow and capital asset pricing models that have been used for decades, no other asset pricing models have generally been adopted for estimating the cost of common equity capital. A recently developed and promising general consumption asset pricing model for estimating costs of common equity is successful in empirical tests and applied for estimating the cost of common equity. This research presents an empirical investigation of the model for application to the regulation of public utilities and stock market and compares the cost of capital results with the CAPM. The model is applicable for estimating the cost of common equity capital for any stock. The paper recommends that the GCAPM be considered as an additional asset model with the others that are typically used as additional information in estimating the cost of common equity capital.

1. Introduction

The state of cost of common equity estimation and modeling has become stale. The only asset pricing models typically used by firms for estimating their cost of common equity are mainly the

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capital asset pricing model (CAPM) with a few firms using the dividend discount cash flow (DCF) and the arbitrage pricing (APM) models, all of which were developed in the 60s and 70s. A survey conducted by the Association for Financial Professionals (2011) on the use of asset pricing models for estimating the cost of capital found that 87% of all firms and 91% of publicly traded firms use the CAPM, 3% of all firms and 2% of publicly traded firms use the DCF model and 1% for both types use the APM. Whereas most firms and much academic research[1] still use the CAPM for cost of capital estimations, the literature on the problems with the empirical evaluation and theoretical foundations of the CAPM is vast and conclusively negative. Fama and French (2004) summarize the literature and conclude that "...In the end, we argue that whether the model's problems reflect weaknesses in the theory or in its empirical implementation, the failure of the CAPM in empirical tests implies that most applications of the model are invalid." This paper does not recommend that the CAPM be discarded or substituted with the GCAPM discussed and tested in this paper. No information should be ignored for estimating the cost of common equity.

Michelfelder and Pilotte (2011) introduced a new asset pricing model for estimating the cost of common equity capital based on the intertemporal asset pricing model literature (discussed below). The generalized consumption asset pricing model requires a minimum of assumptions in its theoretical development. It also is applied with a minimum of subjectivity. Ahern, Hanley, and Michelfelder (2011) performed some cursory preliminary empirical tests and applied the GCAPM to model the risk–return relationship for stocks and estimate the cost of common equity. They used a few public utility stocks to estimate and apply the GCAPM. Public utility applications are important as public utilities are regulated primarily by the allowed rate of return which is supposed to reflect the cost of capital. It is so important to the public utility industries that the initial academic literature on cost of capital estimation and application was based to a major extent on public utility industry studies. See references in Morin (2006).

Ahern et al. (2011) found the GCAPM to be promising in cursory empirical testing and in generating reasonable, mechanically (without subjective judgment) developed estimates of the cost of common equity capital for a small sample of public utilities, consisting of a few electric, electric and gas, natural gas, and water utilities.

Although the model can be used for estimating the cost of capital for any firm, this investigation also focuses on public utility regulation and applications since it is likely to be the most contested issue in a public utility rate proceeding (see Bonbright, Danielsen, & Kamerschen, 1988; McDermott, 2012; Phillips, 1993).[2] Additionally, the practice of public utility regulation has not adopted other models other than DCF and the CAPM (Ahern et al., 2011). These models have numerous strong assumptions and require many subjective judgments in application that leads to highly contested rate of return recommendations in public utility proceedings. The application of these models is highly questionable and the estimates subject to many vagaries due to choices of inputs.

This paper performs an empirical investigation of the GCAPM for public utility cost of common equity estimation.

2. The model

The literature on the traditional CAPM and consumption asset pricing models is vast so that literature is briefly discussed that summarizes the work leading to the model used in this research.

The GCAPM has been recently derived and empirically tested for US Treasury Bonds and Bills and stock market returns in Michelfelder and Pilotte (2011) and preliminarily applied and tested for public

[1] A recent variant of the DCF model has emerged in the academic literature for estimating the cost of common equity capital for other research, the implicit cost of capital. It is essentially the expected book value of a firm plus the capitalized value of the infinite stream of the conditionally expected net income minus the required net income to earn its cost of capital equated to the current stock price. The capitalization rate is the cost of common equity and the same rate implied in the required net income. See Pastor, Sinha, and Swaminathan (2008) and Molina-Ortiz and Phillips (2014).

[2] McDermott (2012) on pp.13–14 states: "While determining the operating costs and rate base is not without controversy, the calculation of the firm's cost of capital is generally one of the most contentious issues in a rate case. ..." The cost of equity is an expectation held by the "marketplace" and is therefore not directly observable. As a result it must be estimated and the question of what is a correct assessment of the market's true value is partly what makes this issue so contentious.

utility stocks and stock markets in Ahern et al. (2011). There are many restrictive versions of the model that led to the derivation of the GCAPM. The main asset pricing models used as foundations to develop the GCAPM include the intertemporal capital asset pricing model in Merton (1973), models in Cochrane (2004), the intertemporal asset pricing model of Campbell (1993), and the habit-persistence model of Campbell and Cochrane (1999).

Some GCAPM highlights are that it (1) makes no assumptions about the efficiency of the asset market, (2) has no constraints on the investor's degree of risk aversion or limits on the magnitude of coefficient of risk aversion, (3) prices the risk that the investor is actually exposed to rather than the nonrealistic systematic risk that assumes that the investor has diversified away all nonsystematic risk. That is, the GCAPM does not assume that the investor has a perfectly diversified portfolio that eliminates all unique risk. The GCAPM even allows for the possibility of a negative relation between return and volatility where other asset pricing models do not. Investors are willing to pay (give up return or accept returns less than the risk free rate) to be exposed to patterns of volatility that hedge against downturns in business cycle levels of consumption. This property will be discussed below and considered in the empirical analysis.

Michelfelder and Pilotte (2011) specify the GCAPM as the *ex ante* risk premium of an asset *i* as a function of the volatility of the asset *i ex ante* return:

$$E_t\left[R_{i,t+1}\right] - R_{f,t} = -\frac{vol_t\left[M_{t+1}\right]}{E_t\left[M_{t+1}\right]} vol_t\left[R_{i,t+1}\right] corr_t\left[M_{t+1}, R_{i,t+1}\right], \tag{1}$$

where $R_{i,t+1}$ is the *ex ante* return on asset *i*, $R_{f,t}$ is the risk free rate of return at time *t*, M_{t+1} is the stochastic discount factor (SDF), vol_t is the volatility of the variable conditioned on information available in time *t*, E_t is the expectations operator conditional on information available in time *t*, and, $corr_t$ is the correlation conditioned on information available in time *t*. The SDF is the intertemporal marginal rate of substitution in consumption:

$$M_{t+1} = \left(\frac{1}{1+k}\right)\frac{U_{c,t+1}}{U_{c,t}}, \tag{2}$$

where the U_c's are the marginal utilities of consumption for the differing time periods and *k* is the discount rate for the period from *t* to *t* + 1. The ratio of the marginal utilities of consumption for two time periods, $U_{c,t+1}/U_{c,t}$, rises if the expected future dollar value of consumption falls below current consumption. This property is due to the concave shape of the investor's utility function and diminishing marginal utility and generates the specification of the model to identify the business cycle (represented by consumption expenditures) hedging property (if any) of an asset.

The ratio, $vol_t\left[M_{t+1}\right]/E_t\left[M_{t+1}\right]$, is the slope of the mean-variance frontier and reflects the expected volatility of utility from consumption relative to expected utility, which is the conditional coefficient of variation in utility. If conditional volatility rises relative to expected value, investors require a greater risk premium as compensation. The algebraic sign of the relation (slope) between the expected risk premium and its conditional volatility is determined by the conditional correlation ($corr_t$) of the expected risk premium and the SDF. The sign of this slope has the opposite sign of the correlation of the asset return and the ratio of intertemporal marginal utilities in consumption. When the correlation is positive (negative), the asset will have a negative (positive) relation with its risk. Since a decline in consumption in an economy is a component of a business cycle contraction, assuming investors have a concave utility function of consumption, a decline in expected consumption increases marginal utility as the investor's consumption moves left on the utility function. The hedging asset generates positive changes in asset returns when the business cycle is in a contraction and therefore the asset is a business cycle and consumption hedge.

Therefore, if the estimated return/risk coefficient is negative, the asset is a business cycle/consumption hedge. Under these circumstances, it is conceivable that an investor may accept a return less than the risk-free rate as she is willing to pay (give up return) to be exposed to this specific pattern of higher volatility. This asset delivers rising returns when the investor needs it most – during a business cycle downturn. A hedging asset pays more during business cycle contractions and less during expansions and therefore plays the role of insurance, paying to avoid hardship.

The slope of the relation between the return and risk is very rich in insight and structure. The slope of the return and volatility relationship is a function of the volatility of the return, the independent variable. As the volatility changes, it affects the $corr_t$ as correlation equals covariance of the two variables divided by the product of the volatility of the two variables.

3. The data

The company stocks in the rate of return regulated electric, electric and gas distribution (combination), natural gas distribution (sometimes referred to as local distribution companies or "LDC's"), and water utility industries are defined by the AUS Utility Reports©,[3] a national public utilities financial consulting firm and database company established in 1968 (www.aus.com). These include all 77 public utility stocks that are publicly traded in the US. The monthly stock total returns for each public utility begin with the first available monthly data observation for each individual utility company stock in the University of Chicago's Booth School of Business Center for Research in Security Prices (CRSP®) database. The data available from CRSP® begins no earlier than January 1926 for stock data in general and ends for this study at December 2011. CRSP® faculty and staff determine how far back to go to obtain accurate stock price and returns data on every stock. Monthly returns observations range from the earliest available date in CRSP® for each stock to December 2011. The risk free rate is the monthly long-term US Treasury bond yields from Morningstar (2012). The US stock market data is the CRSP® Fama–French monthly returns risk premium based on the CRSP® value-weighted stock market index that includes most stocks on the NYSE, NASDAQ, and AMEX and includes approximately 11,000 stocks. This data is publicly available at no cost from Professor Kenneth French's data website (French, 2012).

Table 1 shows descriptive statistics for the monthly risk premium data for each stock and the data observation range for each stock by industry. The annualized compound annual return premia based on the monthly means range from approximately 5% to 7.5%. Standard deviations are about 10–20 times the mean risk premiums (coefficients of variation).

The greatest number of observations are obtained for each stock as more data history capture a longer period of the fundamental nature of asset pricing volatility clustering patterns, whether the patterns are recent or many years old. The nature of autoregressive conditional heteroskedasticity (ARCH) models is based on the fundamental nature of financial markets volatility clustering patterns.

4. Empirical results

An obvious method to estimate Eq. (1), the relation between risk and return, is the generalized autoregressive conditional heteroskedasticity in mean (GARCH-M) model. The GARCH-M model was developed specifically for estimating asset return and volatility relations. GARCH-M is used since it specifies the conditional expected risk premium as a linear function of its conditional volatility, which is the theoretical specification of Eq. (1). Due to the high likelihood of ARCH effects in asset returns the use of GARCH methods will improve the efficiency of the estimates if ARCH effects should be present in the data. The GARCH-M model adopted herein was initially developed and tested by Engle, Lilein, and Robins (1987) to estimate the relationship between US Treasury and corporate bond risk premiums and their expected volatilities. The GARCH-M model is specified (without an intercept in the return equation) as:

$$R_{i,t+1} - R_{f,t} = \alpha_{i,t}\sigma^2_{i,t+1} + \varepsilon_{i,t+1}, \tag{3}$$

$$\sigma^2_{i,t+1} = \beta_0 + \beta_1\sigma^2_{i,t} + \beta_2\varepsilon^2_{i,t} + \eta_{i,t+1}, \tag{4}$$

where $R_{i,t+1}$ is the expected total return on asset i, $R_{f,t}$ is the risk-free rate of return, $\sigma^2{}_{i,t+1}$ is the conditional or predicted variance of the risk premium for asset i that is conditioned on past information,

[3] AUS, Inc. is a holding company of financial consulting, database and marketing research consulting firms. AUS Consultants is a national public utilities financial consulting firm established in 1968. See www.ausconsultants.com.

Table 1
Descriptive statistics by utility industry.

Electric stock Symbols	Monthly mean RP	Std. dev.	Begin period	
AEE	0.00319	0.04812	January	1953
AVA	0.00380	0.06352	October	1952
BKH	0.00701	0.06850	January	1973
CHG	0.00375	0.04869	December	1945
CMS	0.00250	0.07378	March	1947
CNP	0.00609	0.06924	September	1943
CPK	0.00646	0.05888	January	1973
D	0.00660	0.05021	July	1983
DTE	0.00433	0.05509	January	1926
DUK	0.00374	0.05750	August	1961
ED	0.00566	0.06678	January	1926
EDE	0.00445	0.04824	November	1946
ETR	0.00537	0.06362	June	1949
EXC	0.00477	0.05263	August	1943
LNT	0.00462	0.05212	January	1973
MDU	0.00623	0.06120	October	1948
MGEE	0.00499	0.04921	January	1973
NI	0.00245	0.06306	January	1963
NU	0.00287	0.05700	March	1967
NVE	0.00303	0.07535	December	1962
OGE	0.00562	0.05579	October	1950
PCG	0.00508	0.06478	January	1926
PEG	0.00486	0.05421	April	1948
POM	0.00406	0.05045	January	1947
PPL	0.00474	0.05408	January	1946
SCG	0.00589	0.05684	December	1946
SRE	0.00510	0.06067	July	1998
TE	0.00320	0.06615	August	1962
TEG	0.00476	0.04736	June	1953
UGI	0.00527	0.06988	July	1929
UIL	0.00470	0.06512	January	1972
UNS	0.00020	0.08707	June	1969
UTL	0.00479	0.05157	April	1985
VVC	0.00544	0.05821	January	1971
WEC	0.00562	0.04747	December	1947
WR	0.00439	0.05186	August	1949
XEL	0.00513	0.05463	March	1949
Mean	0.00461	0.05889		

Electric stock symbols	Mean RP	Std. dev.	Begin period		Gas stock symbols	Mean RP	Std. dev.	Begin period	
ALE	0.00541	0.53263	April	1950	AGL	0.00592	0.05085	January	1973
AEP	0.00429	0.05421	October	1949	ATO	0.00608	0.06014	January	1984
CNL	0.00707	0.05232	December	1981	DGAS	0.00460	0.04618	May	1981
EIX	0.00559	0.06519	June	1926	EGN	0.00709	0.06478	January	1958
EE	0.00799	0.06749	March	1996	EQT	0.00708	0.06400	July	1950
FE	0.00450	0.05336	October	1946	EGAS	0.00712	0.07676	February	1986
GXP	0.00406	0.05268	October	1950	LG	0.00382	0.08632	January	1926
HE	0.00327	0.05492	November	1964	NFG	0.00562	0.05605	August	1955
IDA	0.00451	0.05363	February	1944	NJR	0.00636	0.06099	January	1973
NEE	0.00671	0.05890	March	1950	NWN	0.00491	0.05826	January	1973
OTTR	0.00449	0.06278	January	1973	OKE	0.00761	0.07400	June	1954
PNM	0.00160	0.07506	October	1972	PNY	0.00630	0.05847	March	1970
PNW	0.00244	0.08241	September	1961	RGCO	0.00490	0.04263	March	1994
SO	0.00809	0.11648	November	1929	SJI	0.00544	0.05631	October	1958
					STR	0.00733	0.07784	February	1961
Mean	0.00500	0.09872			SWX	0.00396	0.06799	January	1973
					WGL	0.00513	0.05847	Feb	1940
					WMB	0.01230	0.13432	Aug	1962
					Mean	0.00620	0.06635		

Table 1 (*Continued*)

Water stock symbols	Mean RP	Std. dev.	Begin period	
ARTNA	0.00620	0.05574	June	1996
AWR	0.00527	0.06154	January	1973
CTWS	0.00488	0.05391	July	1975
CWT	0.00550	0.05655	January	1973
MSEX	0.00558	0.05235	January	1973
SJW	0.00620	0.06565	March	1972
WTR	0.01006	0.07025	August	1971
YORW	0.00912	0.07119	February	2001
Mean	0.00660	0.06090		

The mean RP is the mean of the monthly risk premium returns data for each stock used to estimate the GCAPM with the GARCH models. The mean is calculated from the beginning period and ending in December 2011.

and, $\varepsilon_{i,t}$ and $\eta_{i,t+1}$ are the error terms for the mean and volatility equations, respectively. The parameter, α_i, or "alpha" is the return-to-risk coefficient as specified in Eq. (1) as:

$$\alpha_{i,t} = -\frac{vol_t\,[M_{t+1}]}{E_t\,[M_{t+1}]} corr_t \left[M_{t+1}, R_{i,t+1}\right] \tag{5}$$

This parameter represents the relation between risk premium and volatility and its algebraic sign indicates whether the asset is a business cycle hedge. The parameter itself is a function of the independent variable, the conditional variance, and is time varying as the conditional standard deviation of the return is included in the conditional correlation, $corr_t[M_{t+1}, R_{i,\,t+1}]$, of the stochastic discount factor and the return. The theoretical model, Eq. (1), is specified without an intercept, therefore it is estimated the model without the intercept, but robustness tests are done to evaluate the model with intercepts. Intuitively the intercept should be zero. Otherwise would indicate evidence of an excess return premium or payment (if negative) that is not associated with volatility. The "no-intercept" specification has been found to be robust in producing consistently positive and significant relationships between common stock risk premiums and risk in GARCH-M models. These findings are discussed in Lanne and Saikkonen (2006) and Lanne and Luoto (2007).

Table 2a–d shows the GARCH model estimates for all publicly traded US electric, electric and gas, gas, and water company stocks as well as the US stock market for comparison. The list of utility stocks and their categorization in each industry are defined by AUS Utility Reports® (2012) that is available upon request. The AUS Utility Reports® tracks all US publicly traded electric, gas and water utility stocks. The results show that the model fits almost all of the public utility stock returns and the US stock market returns well as almost all estimated parameters are significant, generally at p-values of 0.01 or less, except for water company stocks that have some p values that are generally less than 0.10, especially for the alpha slope that is used to estimate the cost of capital. Generally, water utility stocks have substantially less stock returns data for modeling.

All but seven of the Lagrange Multiplier ARCH statistics (LM-ARCH), a test for ARCH effects in the residuals, are not significant, indicating that the GARCH-M model is effective at removing most of the ARCH effects from the regression residuals. The sum of the slopes in the variance equation ($\beta_1 + \beta_2$) is close to one for all stocks and the stock market. A value of one or greater indicates the presence of an integrated GARCH process (IGARCH) (Engle & Bollerslev, 1986). Shocks in returns that have an IGARCH process have a permanent effect on the conditional variance and therefore the asset's value.

The slopes on conditional variance, the alphas, are positive and significant for most of the utility stocks (all but seven) and the US stock market. Those that are not significant have alpha estimates that are in a reasonable range of values. These results are evidence that there is a long-term positive relation between risk and return and that none of the assets in this investigation are business cycle consumption hedges as none are negative in algebraic sign. Since utility sales, especially electricity usage and therefore cash flows are generally highly correlated with GDP, positive values were expected for the alpha estimates as utility stocks are not expected to be a business cycle hedge. Fig. 1 from the US Energy Information Administration's 2013 Annual Energy Outlook shows the close association between GDP and electricity use growth rates. As the energy intensity of GDP continues to decline

Table 2a
Electric utility stocks and US stock market GARCH-M estimations of risk–return relations.

Asset	Mean equation	Variance equation			LM-ARCH
	$\sigma^2_{i,t+1}$	Constant	$\sigma^2_{i,t}$	$\varepsilon^2_{i,t}$	
US Stocks (CRSP)	2.869***	0.000***	0.841***	0.128***	0.56
Electric utility stock symbols					
ALE	2.072***	0.000**	0.851***	0.094***	0.72
AEP	2.197***	0.000**	0.789***	0.112***	1.12
CNL	2.968***	0.000**	0.685***	0.180***	0.71
EIX	1.536***	0.000***	0.873***	0.108***	1.32
EE	1.853***	0.000	0.882***	0.090	1.14
FE	2.161***	0.000**	0.755***	0.158***	0.79
GXP	2.289***	0.000***	0.812***	0.149***	0.62
HE	1.634**	0.000***	0.786***	0.144***	0.88
IDA	1.981***	0.000**	0.851***	0.097***	0.93
NEE	2.166***	0.000**	0.871***	0.082***	0.74
OTTR	1.378**	0.001***	0.489***	0.248***	0.70
PNM	0.984	0.000***	0.834***	0.116***	0.52
PNW	1.142**	0.000***	0.639***	0.260***	2.03**
SO	0.944***	0.000**	0.894***	0.103***	0.57

The results are for all publicly traded electric utility stocks. The results are the GARCH-M regressions for the monthly risk premium on the asset ($R_{i,t+1} - R_{f,t}$) with conditional variance in the mean equation. The estimated model is:
$R_{i,t+1} - R_{f,t} = \alpha_{i,t}\sigma^2_{i,t+1} + \varepsilon_{i,t+1}$, where $\alpha_{i,t} = -(vol_t[M_{t+1}]/E_t\,[M_{t+1}])corr_t[M_{t+1}, R_{i,t+1}]$
$\sigma^2_{i,t+1} = \beta_0 + \beta_1\sigma^2_{i,t} + \beta_2\varepsilon^2_{i,t} + \eta_{i,t+1}$
The monthly data ranges from the earliest returns data available for each asset in the CRSP database (earliest returns data available is January 1926) and ends at December 2011. The return variable for US Stocks is the monthly risk premium on the value weighted CRSP stock returns from the Fama–French CRSP database. Engle's Lagrange Multiplier ARCH statistic (LM-ARCH) is a test for ARCH effects in the residuals for 12 lags. It is χ^2 distributed with 12 degrees of freedom where the degrees of freedom are driven by the number of lags tested. Standard errors are in parentheses. ***, **, * denote p-values equal to less than 0.01, 0.05, and 0.10 levels, respectively, with two-tailed tests for regression coefficients and one-tailed test for LM-ARCH.

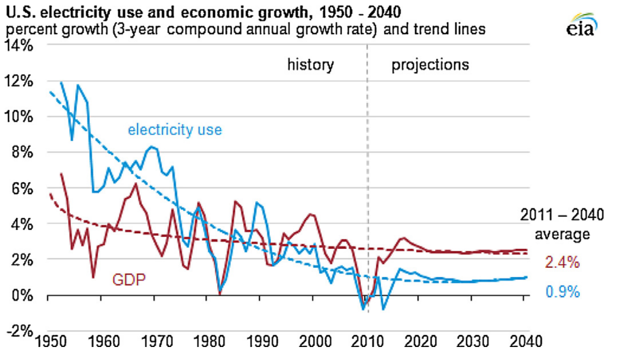

Fig. 1. Relation between GDP and electricity use.

due to the adoption of energy efficiency technologies, the growth rates of GDP and electricity use in recent years have started to moderately decouple and is expected to continue to do so.

Fig. 2 plots the average of the rolling estimated alpha for each utility industry group for each month from January 2006 to December 2011 to review the stability and trends in the alphas. Although not shown for each stock, the alphas range in value from about 0.5 to almost 3.0 and are relatively stable across all stocks used in obtaining the averages. They do not become negative (switch to temporary business cycle hedges) at any point during the study period. Note that all of the stocks' alphas in all of the industries are quite similar in pattern and stability. All of them drop as the US business cycle enters

Table 2b
Electric and gas utility stocks GARCH-M estimations of risk–return relations.

Asset	Mean equation	Variance equation			LM-ARCH
	$\sigma^2_{i,t+1}$	Constant	$\sigma^2_{i,t}$	$\varepsilon^2_{i,t}$	
Electric and gas utility stock symbols					
AEE	1.507**	0.000**	0.823***	0.106***	1.81**
AVA	0.980*	0.000***	0.863***	0.150***	0.10
BKL	1.289*	0.000**	0.838***	0.097***	0.71
CHG	2.154***	0.000***	0.823***	0.117***	0.66
CMS	1.469***	0.000***	0.817***	0.180***	1.07
CNP	1.976***	0.000***	0.732***	0.172***	1.99**
CPK	1.896**	0.000	0.961***	0.025**	0.52
D	2.406**	0.000*	0.806***	0.121***	1.08
DTE	2.201***	0.000***	0.852***	0.128***	1.75**
DUK	1.901***	0.000**	0.809***	0.137***	0.31
ED	1.151***	0.000***	0.854***	0.138***	0.49
EDE	2.248***	0.000**	0.806***	0.068***	0.98
ETR	2.273***	0.000***	0.838***	0.124***	0.99
EXC	1.975***	0.000***	0.874***	0.090***	1.05
LNT	2.302**	0.000**	0.775***	0.135***	0.38
MDU	1.642***	0.000***	0.811***	0.115***	1.12
MGEE	2.281**	0.000**	0.765***	0.057**	0.74
NI	1.604**	0.000**	0.818***	0.132***	0.99
NU	1.283*	0.000***	0.838***	0.123***	2.10**
NVE	1.228**	0.000***	0.903***	0.079***	0.35
OGE	2.266***	0.000***	0.777***	0.128***	0.67
PCG	1.836***	0.000***	0.860***	0.118***	0.84
PEG	2.304***	0.000**	0.888***	0.095***	0.72
POM	2.221***	0.000***	0.863***	0.079***	0.40
PPL	1.809***	0.000***	0.829***	0.113***	1.19
SCG	2.401***	0.000***	0.761***	0.150***	0.53
SRE	1.906	0.000	0.806***	0.132*	0.41
TE	1.418**	0.000***	0.823***	0.136***	0.47
TEG	2.856***	0.000*	0.832***	0.086***	0.21
UGI	1.400***	0.000***	0.923***	0.058***	0.37
UIL	1.665**	0.000***	0.764***	0.182***	0.94
UNS	0.764	0.000***	0.864***	0.100***	0.72
UTL	0.822	0.000**	0.715***	0.128**	0.56
VVC	1.896**	0.000***	0.869***	0.081***	0.62
WEC	2.758***	0.000*	0.844***	0.056**	1.15
WR	2.236***	0.000***	0.886***	0.072***	2.04**
XEL	2.633***	0.000***	0.756***	0.167***	0.76

See Table 2a notes.

the great recession from the December 2007 peak to the June 2009 trough and the only recession during the study period (National Bureau of Economic Research, 2015). An increasing (decreasing) alpha indicates that the price of risk has increased (decreased). These alphas are Sharpe ratios (Sharpe, 1994), the ratio of the expected risk premium to conditional volatility. Higher alphas should not be interpreted as higher risk and therefore higher expected rates of return on common equity. A higher price of risk can be associated with lower volatility and lower rather than higher costs of common equity. Alpha is inversely related to the volatility in return in the theoretical development of the model. Therefore a higher volatility is combined with a lower alpha so the overall impact of a higher alpha on the expected rate of return is not clear. It is possible that the drop in alphas approaching and during the recession may be due to investors' flight to quality to assets with lower risk and lower but acceptable return.

Fig. 3 shows the GCAPM cost of common equity results and their trends for each of the public utility industries. The alpha coefficients and predicted monthly volatilities used to estimate the cost of common equity for each public utility stock are estimated using a series of estimated GARCH models for each utility as discussed above. Consistent with Ahern et al. (2011), the *ex ante* common equity risk

Table 2c
Gas (local distribution companies or LDC) utility stocks GARCH-M estimations of risk–return relations.

Asset	Mean equation	Variance equation			LM-ARCH
	$\sigma^2_{i,t+1}$	Constant	$\sigma^2_{i,t}$	$\varepsilon^2_{i,t}$	
Gas utility stock symbols					
AGL	2.787***	0.000**	0.803***	0.096***	0.57
ATO	2.143***	0.003***	−0.081	0.261***	0.58
DGAS	2.195*	0.003*	−0.360	0.051	0.23
EGN	2.215***	0.000***	0.766***	0.171***	0.76
EQT	1.814***	0.000***	0.834***	0.131***	0.46
EGAS	1.150	0.000***	0.732***	0.197***	0.36
LG	0.855**	0.000***	0.896***	0.097***	0.66
NFG	1.596***	0.000***	0.901***	0.079***	0.86
NJR	1.944**	0.002***	0.351**	0.276***	0.11
NWN	1.604**	0.000**	0.796***	0.117***	0.92
OKE	1.569***	0.000***	0.810***	0.139***	0.80
PNY	2.287***	0.000***	0.837***	0.106***	0.98
RGCO	2.153***	0.000**	0.962***	-0.059***	0.94
SJI	1.989***	0.000***	0.755***	0.138***	0.94
STR	1.381**	0.001**	0.866***	0.036***	0.11
SWX	1.177*	0.000***	0.823***	0.087***	0.34
WGL	1.092**	0.000***	0.831***	0.170***	0.25
WMB	0.824**	0.000***	0.813***	0.131***	2.68***

See Table 2a notes.

Table 2d
Water utility stocks GARCH-M estimations of risk–return relations.

Asset	Mean equation	Variance equation			LM-ARCH
	$\sigma^2_{i,t+1}$	Constant	$\sigma^2_{i,t}$	$\varepsilon^2_{i,t}$	
Water utility stock symbols					
ARTNA	1.879	0.000**	0.838***	0.094**	0.93
AWR	1.389*	0.000*	0.873***	0.047	0.74
CTWS	1.636*	0.001**	0.529***	0.157***	0.44
CWT	1.706**	0.000**	0.793***	0.111***	0.86
MSEX	1.880**	0.000**	0.805***	0.087**	0.94
SJW	1.273*	0.000**	0.911***	0.043***	0.68
WTR	2.110***	0.000***	0.857***	0.079***	1.15
YORW	1.819	0.000	0.852***	0.029	0.63

See Table 2a notes.

premiums were calculated using the average of predicted volatilities (variances) over the entire time period for which CRSP data were available for each utility and then multiplied by α_i's. The GCAPM cost of common equity for each utility was estimated by adding the average predicted utility's common equity risk premium for each month starting in January 2006 through December 2011 to the predicted risk free rate, which is the consensus forecast of the 30 year US Treasury Bonds yield for the next 6 quarters from Blue Chip Financial Forecasts. Fig. 3 shows that the predicted cost of common equity capital results generated by the GCAPM was stable for all utility industries except for the recession and associated global financial market crisis of 2008 and 2009. During that period, predicted GCAPM costs of capital declined. This may have been due to investors' flight to quality to less risk and an acceptable lower return. The GCAPM predicted costs of capital for all of the utility industry groups follow a similar trend except for the water utilities, which had a similar path but much more volatility. Contrasting with the CAPM that uses only one estimated parameter, beta, to establish the uniqueness among each stock, the GCAPM uses two estimated parameters to predict the expected returns, the alpha and the specific stock predicted conditional volatility and three more parameters in the variance prediction model for predicting volatility. Since it is investors' behaviors that cause the level of volatility and due to the fact that the GCAPM uses predicted volatilities to predict the cost of capital, the GCAPM is more

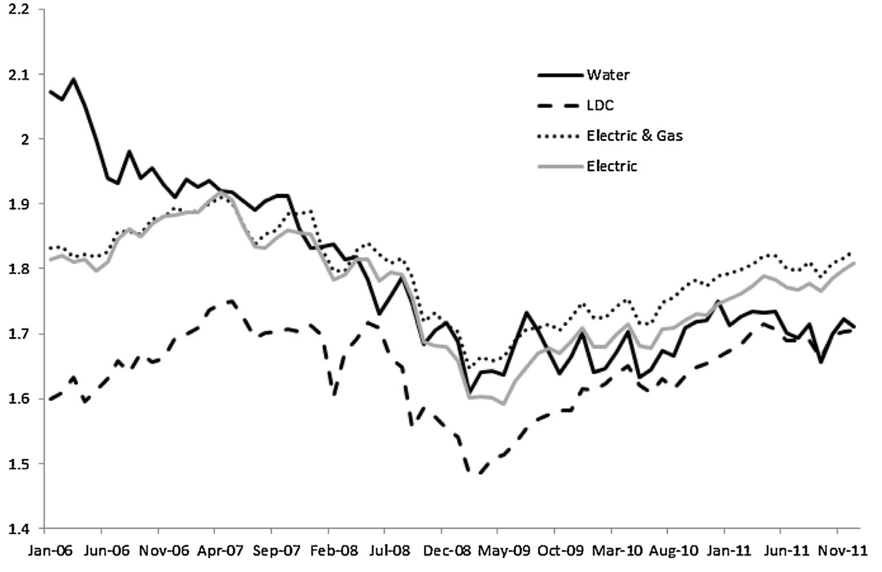

Fig. 2. Alphas (slope on $\sigma^2_{i,t+1}$) from 1/2006 to 12/2011 for electric, electric and gas, gas (local distribution companies or LDC) and water utility stocks. The stocks in each industry are those as defined by AUS Utility Reports® (AUS, 2012). See Table 1 for individual stocks.

intuitive appealing than the CAPM. The CAPM is not a forward-looking model and beta is not a pure measure of risk. It is a mixture of correlation and risk.[4]

Fig. 4 shows the plots the averages of the costs of common equity for each stock estimated with the GCAPM and the CAPM for each of the utility industries. The plots consistently show that the GCAPM generates a substantially higher cost of capital than the CAPM. This may be due to the fact that the GCAPM prices the risk which investors actually face whereas the CAPM prices systematic risk, the only risk that the investor would be exposed if they had a perfectly diversified portfolio, which does not exist in practice. Based on the well-established observation of low R^2's of CAPM regressions, a substantial majority of a stock return's volatility is not explained by the CAPM (Fama & French, 2004) and therefore not priced by the CAPM.

The only recession that occurred during the period shown on the graphs is the great recession that started with the peak at December 2007 and the trough at June 2009 (National Bureau of Economic Research, 2015) as mentioned above. As investors anticipated the future of the business cycle, both the alphas and the costs of common equity peaked as shown in Figs. 2–4 then declined and reached the trough a few months before the business cycle. Note (Fig. 4) that the GCAPM costs of capital peaks and troughs precede those of the CAPM by somewhat less than a year. This suggests that the GCAPM is a forward looking model more than the CAPM as it leads CAPM peaks and troughs in the cost of capital and is able to anticipate CAPM generated trends in the cost of capital. This evidence is not meant to conclude that the CAPM should be replaced by the GCAPM. Until one model un-equivocally produces results deemed to be closer to the true cost of common equity, no information should be ignored for consideration in estimating the cost of common equity. This investigation suggests that the GCAPM

[4] The CAPM beta is defined as $\beta_i = \rho_{i,m}\,\sigma_i\,\sigma_m/\sigma_m{}^2$ where $\rho_{i,m}$ is the correlation between the returns on stock i and the market, and the σ's are the standard deviations on stock i and market returns (m). Since the expression can be simplified to $\beta_i = \rho_{i,m}$ (σ_i/σ_m), only the ratio of standard deviation of the stock to the market return represents volatility and therefore risk. So the CAPM beta is a mixture of correlation and risk. A high ratio of volatility of a stock's return relative to the market combined with a low correlation can result in a low beta, reflecting low risk.

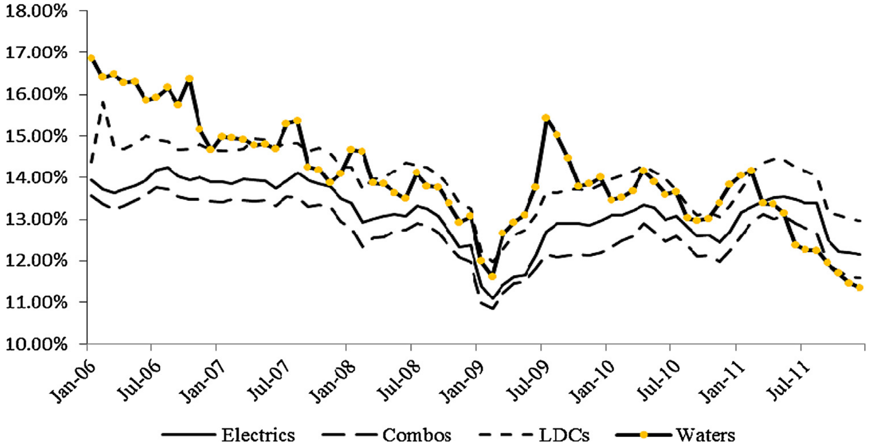

Fig. 3. GCAPM cost of common equity estimates for US publicly traded public utilities.

model contributes additional information that should be considered in the process for estimating the costs of common equity. Hopefully, additional information and technologies will diffuse into the process rather than almost sole reliance on the CAPM.

Michelfelder, Ahern, D'Ascendis, and Hanley (2013) show the trends in the cost of common equity estimates by each asset model for each industry. They perform a comparison of the results of the two typical used asset pricing models, the DCF and CAPM with the GCAPM. The GCAPM generally produces higher predicted ROE's than either the DCF or CAPM. Since the GCAPM prices the actual risk faced by the investor rather than the lower, unrealistic ideal (perfectly diversified portfolio) level assumed by the CAPM, this result is not surprising. Public utilities are not investing the level of capital investment necessary to maintain the current level of service, much lesser than the capital needed for growth in their service areas. Regulated allowed rates of return on common equity lower than the costs of common equity may be the cause of public utilities lack of investment that is expected to generate deterioration of service and inhibit economic growth if it does not change soon. For example, the Brattle Group, Fox-Penner, Chupka, and Earle (2008) estimates that the US electric power industry will have to invest $1.5 trillion to $2.0 trillion by 2030 to maintain the current level of reliability. Brennan (2008) shows that electricity transmission capacity peaked in 1982 and that both capacity and investment has been on a long-term declining trend. According to the US EPA's 2011 Drinking Water Infrastructure Needs Survey and Assessment (EPA, 2011), by 2030 the industry will require $384.2 billion in 2011 dollars in system upgrades to maintain safe drinking water service. Such a huge level of investment will cause water rates and bills to rise to levels similar to electricity bills.

5. Robustness tests

Robustness tests are performed with the inclusion of an intercept, differing specifications of conditional volatility, and the use of the Fama–French risk-free rate for generating risk premia. The estimation results are poor with the inclusion of an intercept therefore the model is well specified. All of the model estimations are robust to changes in specifications of the conditional volatility using standard deviation and the natural log of variance as other measures. Similarly, the estimations are robust to choice of risk-free rate.

One concern is the intertemporal stability of the alphas. The alpha in the model is a function of conditional variance and is time varying as the conditional standard deviation of the return is included in the conditional correlation of the stochastic discount factor and the return. The averages of the alpha estimates are plotted over time for each utility to review stability of the hedging property of the assets

Fig. 4. Plots of GCAPM and CAPM costs of common equity estimates for electric, electric and gas, gas, and water utility stocks.

over time. Fig. 2, as already discussed, plots the updated monthly alphas over 72 months (January 2006 to December 2011). The alpha values are highly stable and never get close to zero and, generally, there are no discontinuous spikes in alpha in either direction for each utility stock.

6. Conclusion

Based on the results of this empirical study, Ahern et al. (2011), Michelfelder et al. (2013), and Michelfelder and Pilotte (2011), a literature is beginning to emerge that supports the GCAPM as additional evidence for estimating the cost of common equity capital. This study found that the model fits the data well across all US publicly traded utility stocks and the US stock market as a single portfolio. The estimates are consistent, stable, and show that utility stocks are not a business cycle hedge. There would be a stability concern if some utility stocks were hedges and others were not or if stocks temporarily switched to hedging assets.

The GCAPM has been successfully empirically tested for public utilities and the US stock market in this study and preliminarily in Ahern et al. (2011), and for US Treasury Bills and Bonds in Michelfelder and Pilotte (2011). However, a comprehensive study across a spectrum of common equity assets, at least for non-public-utility individual stocks, is needed as an important next step to consider the widespread adoption of the GCAPM as a method to estimate the cost of common equity capital for stocks in general. This paper is a component of a research program toward that goal. The motivation was to empirically test and discuss the results in sufficient technical detail to assess the relevance of the model for public utility cost of common equity capital estimation and the cost of capital for any firm. Secondly, the motivation was to build a platform for further research of the GCAPM for estimating the rate of return for any stock, as stated above. Finally, the GCAPM was tested as a potential cost of capital model to help update and improve on the cost of capital technology by providing additional information. This paper does not suggest that the GCAPM supplant any other cost of capital pricing model. It does recommend that it be considered as an additional model for developing the cost of capital estimates.

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Comparative Evaluation of the Predictive Risk Premium Model, the Discounted Cash Flow Model and the Capital Asset Pricing Model for Estimating the Cost of Common Equity

The regulatory process for setting a utility's allowed rate of return on common equity has generally relied upon the Gordon Discounted Cash Flow Model and Capital Asset Pricing Model. The Predictive Risk Premium Model, introduced a year ago, resolves several of the widely known problems with these models. Further testing since its introduction a year ago suggests that it produces stable results which are consistent over time.

Richard A. Michelfelder, Pauline M. Ahern, Dylan W. D'Ascendis and Frank J. Hanley

I. Introduction

The lead article in the July 2008 issue of this *Journal*, "Integrating Renewables into the US Grid: Is it Sustainable," by Professors Peter Mark Jansson and Richard A. Michelfelder,[1] called for the reregulation of the electric utility industry and putting the planning of generation assets, whether renewable or not, back in the hands of the experts and those ultimately responsible for reliability, the electric utilities. During the last 10 years or so,

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states have been backpedaling on deregulation and therefore methods for estimating the cost of common equity and the allowed rate of return have generated new interest as regulating rate of return is not going away as once thought.

The regulatory process for setting a public utility's allowed rate of return on common equity has generally relied upon the familiar Gordon Discounted Cash Flow Model (DCF) and Capital Asset Pricing Model (CAPM). Despite the widely known problems with these models, there has been little initiative to adopt more recently developed asset pricing models with fewer limiting assumptions and requiring less subjective judgment than these traditional models. In December 2011, the article "New Approach to Estimating the Cost of Common Equity Capital for Public Utilities,"[2] published in *The Journal of Regulatory Economics*, introduced the Predictive Risk Premium Model (PRPM). The PRPM trademark refers to a general, yet simple, consumption-based asset pricing model of the risk/return relationship for common stocks which can be used to estimate the cost rate of common equity (ROE). The stability and consistency of the results of PRPM and the ex ante, i.e., expectational, nature of those results indicate that the model should be used to provide additional input into the process of determining an allowed rate of return on common equity for public utilities.

Since publication, more exhaustive empirical testing of the PRPM was conducted for the four utility industry groups which comprise the AUS Utility Reports[3] universe of publicly traded utilities: an electric utility group; a combination electric and natural gas distribution utility group; a natural gas distribution utility group, and a water utility group. The empirical testing confirms the conclusion of the original *Journal of Regulatory Economics* article: the PRPM produces stable results which are consistent over time.

Despite the widely known problems with these models, there has been little initiative to adopt more recently developed asset pricing models with fewer limiting assumptions and requiring less subjective judgment.

II. Development of the PRPM

The cost rate of common equity is not directly observable in the capital markets and must be inferred using various financial models. The most commonly used cost of common equity models in the regulatory arena are the aforementioned DCF and the CAPM. Since these models are based upon many restrictive assumptions, they involve a significant amount of analyst subjectivity in their application, resulting in much debate over the application and results of these models.

The empirical approach to the PRPM is based upon the work of Robert F. Engle, Ph.D.,[4] who shared the Nobel Prize in Economics in 2003 "for methods of analyzing economic *time series* with time-varying volatility (*ARCH*),"[5] with "ARCH" standing for autoregressive conditional heteroskedasticity. In other words, volatility (variance) changes over time and is related to itself from one period to the next, especially in financial markets. Engle discovered that the volatility (usually measured by variance) in prices and returns clusters over time. Therefore, volatility is highly predictable and can be used to predict future levels of risk. The theoretical asset pricing model was recently developed in the *Journal of Economics and Business* in December 2011 by Rutgers University professors Richard Michelfelder and Eugene Pilotte.[6]

In this study, the PRPM estimates the risk/return relationship directly using the outcomes of investors' historical pricing decisions and actual long-term U.S. Treasury security yields, with the predicted equity risk premium generated by the prediction of volatility, i.e., the risk, based upon the volatility of past equity risk premiums for the AUS Utility Reports universe of companies.

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III. Estimation Method

The statistical details of the estimation method of the PRPM can be found in the original article in the *Journal of Regulatory Economics*, "New Approach to Estimating the Cost of Common Equity Capital for Public Utilities." Essentially, there are two steps to the application of the PRPM. First, predicted volatility, i.e., risk, is derived based upon previous volatility plus previous prediction error, because volatility is highly predictable and correlated over time. Second, the predicted volatility can then be used to generate the predicted equity risk premium (ERP) by multiplying it by the GARCH coefficient, i.e., the slope of the predicted volatility. A risk-free rate is then added to the ERP to estimate the ROE, i.e., the market based cost of common equity.

IV. Application of the PRPM to Publicly Traded Utility Companies

The PRPM was applied to the companies comprising the AUS Utility Reports' utility industry groups: the electric, combination electric and natural gas distribution, natural gas distribution, and water groups. The PRPM variances were calculated monthly for each individual utility beginning with the first available monthly data included for each individual utility in the University of Chicago Booth School of Business' Center for Research in Security Prices (CRSP) and corresponding monthly long-term U.S. Treasury bond yields from Morningstar's *Ibbotson SBBI – 2012 Valuation Yearbook – Market Results for Stocks, Bonds, Bills and Inflation – 1926–2011 (SBBI)* through 72-month ending periods, i.e., January 2006 through December 2011.

Using EViews Version 7.2, the PRPM coefficients and predicted monthly variances were estimated as described in the *JRE* article for each time series of equity risk premiums. Consistent with the conclusion drawn in the *JRE* article, the predicted equity risk premiums were calculated using the averaged predicted volatilities (variances) over the entire time period for which CRSP data were available for each utility, multiplied by the GARCH, or slope, coefficient generated through EViews for each time series. To calculate the PRPM cost rate of common equity for each utility, the average predicted utility specific equity risk premium through each month ending from January 2006 through December 2011 was then added to the projected consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the next six quarters by the reporting economists in the concurrent *Blue Chip Financial Forecasts (Blue Chip)*.

The DCF was applied in a simple manner, using a dividend yield, D_0/P_0, derived by dividing the month-end indicated dividend per share (D_0) by the month-end closing market price (P_0) for each utility. The dividend yield was then grown by the month-end I/B/E/S consensus five-year projected earnings per share (EPS) growth rate (g) to derive (D_0 $(1 + g)/P_0$). The one-month predicted dividend yield was then added to the concurrent month's I/B/E/S consensus

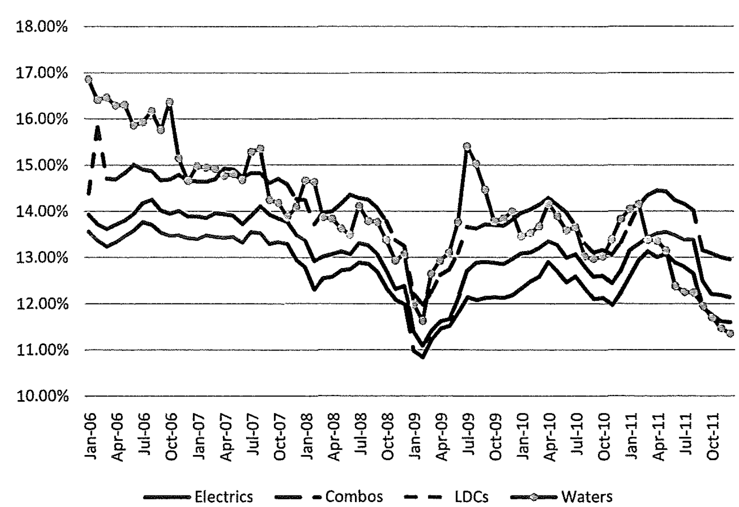

Figure 1: Indicated Return on Common Equity Based upon the PRPM for the AUS Utility Reports Companies

five-year average projected EPS growth rate to obtain the DCF estimate of the cost of common equity capital, *k*. The DCF estimates were also calculated for each month from January 2006 through December 2011.

The CAPM was applied by multiplying Value Line Inc.'s beta (β),[7] for each utility, by the long-term historical arithmetic mean market equity risk premium ($R_m - R_f$) through the previous year. ($R_m - R_f$) was derived as the spread of the total return of large company common stocks over the income return on long-term government bonds from the annual *SBBI Valuation Yearbooks* for the years ending 2005 through 2010. The resulting utility-specific equity risk premium was then added to the same projected consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the next six quarters by the reporting economists in the concurrent *Blue Chip* discussed above, to obtain the CAPM estimate of the cost of common equity capital, *k*. The CAPM estimates were also calculated for each month from January 2006 through December 2011.

Finally, the results for each of the models, the PRPM, DCF, and CAPM, were averaged for each utility group.[8] **Figure 1** presents the average PRPM results for each of the AUS Utility Reports utility groups for each month from January 2006 through December 2011.

Figure 1 shows that indicated ROEs derived from the PRPM were stable for all utility groups until the global financial crisis of 2008–2009. During 2008 and 2009, the PRPM-derived ROEs decline, which in the authors' opinion, was a result of a "flight to quality" by investors, i.e., the willingness of an investor to accept a lower, but more certain, return during financial downturns. Figure 1 also indicates that the PRPM-derived ROEs for the electric, combination electric and natural gas distribution, and natural gas distribution utility groups follow a nearly identical pattern throughout the 72-month period, with the water utility group following a similar, but more volatile pattern.

Figures 2–5 present a comparison of the average PRPM, DCF, and CAPM cost of common equity estimates for each AUS

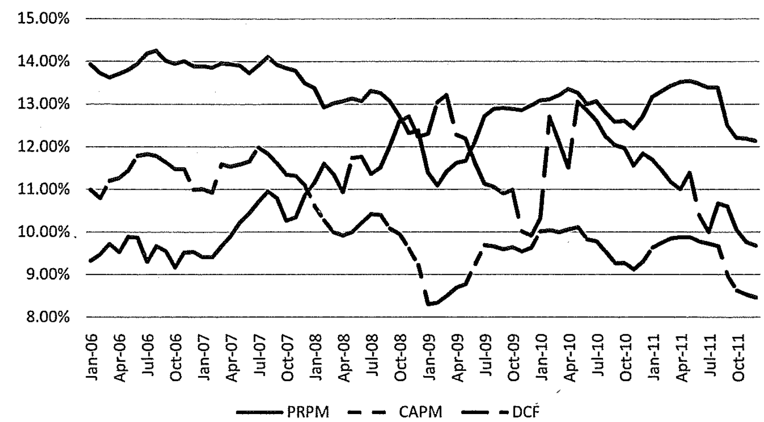

Figure 2: Indicated Return on Common Equity Based upon the PRPM, CAPM and DCF Methodologies for the AUS Utility Reports Electric Companies

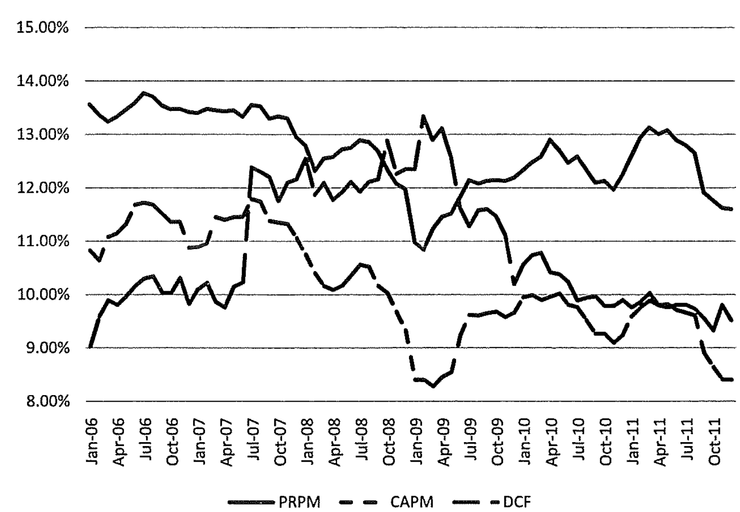

Figure 3: Indicated Return on Common Equity Based upon the PRPM, CAPM, and DCF Methodologies for the AUS Utility Reports Combination Companies

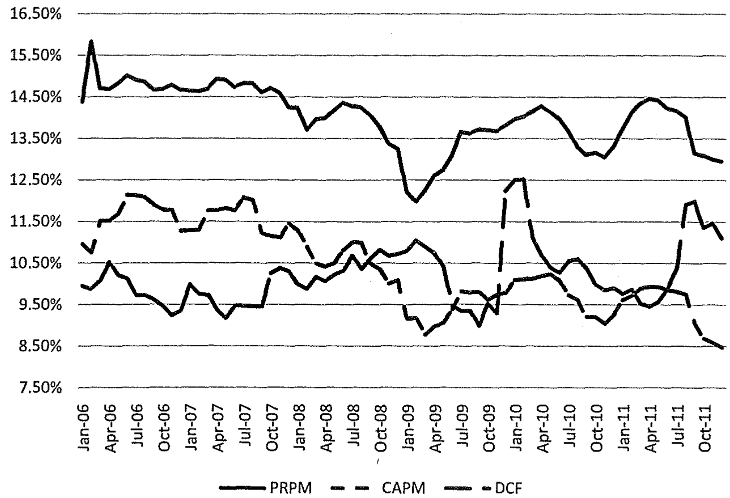

Figure 4: Indicated Return on Common Equity Based upon the PRPM, CAPM and DCF Methodologies for the AUS Utility Reports Gas Companies

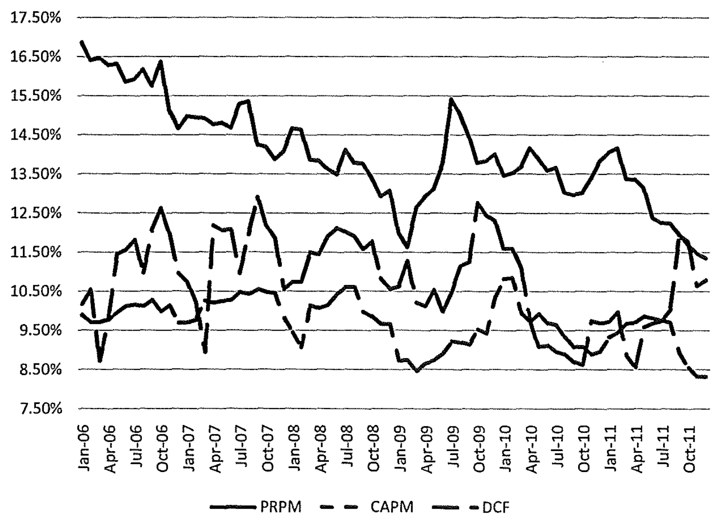

Figure 5: Indicated Return on Common Equity Based upon the PRPM, CAPM and DCF Methodologies for the AUS Utility Reports Water Companies

Utility Reports utility industry group, i.e., the electric utility group; the combination electric and natural gas distribution utility group; the natural gas distribution utility group; and, the water utility group for each month from January 2006 through December 2011.

Figures 2–5 clearly show that, for the most part, the PRPM produces a higher average indicated ROE than both the DCF and CAPM. This is due to the fact that the PRPM prices *all* of the risk that investors actually face collectively. In contrast, the CAPM prices systematic risk (that investors face only if they have a perfectly diversified portfolio, which does not exist) and the DCF uses accounting-based, not market-based, I/B/E/S consensus five-year projected EPS growth rates.

V. Conclusion

In the authors' opinion, the PRPM benefits ratemaking with an additional model to estimate ROE. To that end, the authors have been including the PRPM in their rate-of-return testimonies and the model has been presented publicly in several venues.[9]

Its results are stable and consistent over time. It is not based upon restrictive assumptions, as are the DCF and CAPM. The PRPM is also not based upon an *estimate* of investor behavior, but rather, upon a statistical analysis of *actual* investor behavior by evaluating the results of that behavior, i.e., the volatility (variance) of historical equity risk premiums. In contrast, subjective decisions surround the choice of the inputs to both the DCF and CAPM, from the choice of the time period over which to measure the dividend yield for the DCF, the choice of the DCF growth rate (e.g., historical or projected, earnings per share or dividends per share, and the like), to the selection of the appropriate beta (e.g., adjusted or unadjusted), market equity risk premium (e.g., historical or projected) and the appropriate

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risk-free rate (e.g., historical or projected and/or long vs. short term) for the CAPM. In addition, as previously discussed, the CAPM exclusively prices systematic risk. In contrast, the PRPM prices *all* of the risk actually faced collectively by investors, because the model does not assume that investors' portfolios are perfectly diversified containing no unsystematic risk.

In addition, the inputs to the PRPM are widely available. The GARCH coefficient is calculated with the relatively inexpensive EViews, or other statistical, software, based upon the realized ERP, i.e., total returns minus the risk-free rate. The only subjective decisions to be made when applying the PRPM relate to which risk-free rate to use, e.g., long-term or short-term, and over what time period to estimate the PRPM-derived ROEs.

For all of these reasons, the authors conclude that the PRPM should be considered as appropriate additional evidence to measure the cost of common equity in regulatory rate setting for public utilities.■

Endnotes:

1. Peter Mark Jansson and Richard A. Michelfelder, *Integrating Renewables into the US Grid: Is It Sustainable?* ELEC. J.,July 2008, at 9–21.

2. Pauline M. Ahern, Frank J. Hanley and Richard A. Michelfelder, *New Approach to Estimating the Cost of Common Equity Capital for Public Utilities*, J. REG. ECON.(2011) 40, at 261–78.

3. AUS Monthly Utility Reports is a monthly pocket reference book covering the electricity, combination electricity & natural gas distribution, natural gas distribution, and water companies which have publicly traded common stock. The monthly reports provide comprehensive information on key ratios and industry rankings based upon the financial statistics presented in the report.

4. Professor Emeritus, University of California, San Diego, and currently the Michael Armellino Professor in Management of Financial Services at New York University's Stern School of Business.

5. See www.nobelprize.org.

6. Richard Michelfelder and Eugene Pilotte, *Treasury Bond Risk and Return, the Implications for the Hedging of Consumption and Lessons for Asset Pricing*, J. ECON. & BUS.(2011) 63, at 605–37.

7. Using a proprietary data base available at mid-March, June, September, and December at the end of each year, from 2006–2011 from Value Line, Inc.

8. The results shown in the accompanying figures represent AUS Utility group averages of only those utilities in each group for which it was possible to estimate all three models in any given month. For example, if ABC Utility did not have the I/B/E/S consensus growth rate necessary to calculate the DCF in a given month, that utility's PRPM and CAPM were not included in the group average for that month.

9. Edison Electric Institute Cost of Capital Working Group (Webinar Oct. 2012); NARUC Staff Subcommittee on Accounting & Finance (Sept. 2012 and Mar. 2010); National Association of Water Companies Finance/ Accounting/Taxation and Rates & Regulations Committees (Mar. 2012); NARUC Water Committee (Feb. 2012); Wall St. Utility Group (Dec. 2011); IN Utility Regulatory Commission Cost of Capital Task Force (Sept. 2010); Financial Research Inst. of the Univ. of Missouri Hot Topic Hotline Webinar (Dec. 2010); and Center for Research in Regulated Industries Annual Eastern Conference (May 2010 & May 2009).

Subjective decisions surround the choice of the inputs to both the DCF and CAPM.

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Decoupling, risk impacts and the cost of capital

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ABSTRACT

Public utilities and regulators are decoupling revenues from sales to remove a disincentive for utilities to invest in end-use electricity, natural gas and water efficiency. Decoupling is primarily a US ratemaking policy for energy and water utilities as are price caps in Europe. Empirical testing consistently demonstrates that decoupling has no statistically measurable impact on risk and the cost of common equity, yet policy is moving ahead without consideration of that empirical evidence.

1. Introduction

In the late 1970s, US policymakers, legislators, regulators and public utilities began focusing on reducing consumers' demand for energy rather than increasing supply. This was mainly a reaction to the oil supply shock in the US in the early 1970s, beginning with the National Energy Conservation Act of 1978. Europe was already much more efficient in the use of energy by the 1970s as the BTU content of GDP for many European countries was a substantially small fraction relative to the US.

More recently in the US, regulatory policy has required water utilities to encourage the reduction in water use by their consumers. The US and European utility industries seem to observe each other's experiments in decoupling and price caps before adopting such alternative ratemaking policy movements. Price cap regulation, where utility prices are allowed to rise to a cap set by an inflation index minus a total productivity factor offset that reflects potential cost savings, was implemented decades ago for British utilities. Later it was adopted by many other utilities in Europe (EU). However, in the US, very few utilities are under price cap regulation except for telecommunications local exchange carriers. In contrast, decoupling, which effectively disassociates revenue levels from commodity (electric, gas or water) sales has been sweeping across the US in the last two decades for energy and water utilities, while not being adopted in Europe.

Campini and Rondi[1] show that alternative rate mechanisms in the EU have been in the form of price caps to promote efficient investment and operating expenditures without mentioning decoupling. They note that since many utilities in the EU are government owned, there has not been any major adoption of alternative regulatory rate making methods across the utility industry as EU utility rates are not regulated. Therefore, this study is limited to analyzing decoupling in the US, as it is still almost exclusively a regulatory tool implemented in the US.

The profit disincentive associated with revenue and profit reductions is a major financial impediment preventing investor-owned utilities from encouraging the conservation of energy and water usage and sales. In response, various regulatory policy mechanisms have been developed to provide utilities with a financial incentive, or, at least, remove the disincentive, to utilities to encourage energy and water efficiency. One such mechanism is the inclusion of conservation expenditures in rate base so that such expenditures earn a return. Other mechanisms allow for a profit incentive equal to a proportion of the life cycle of net benefits, as well as rate of return premiums for meeting or exceeding conservation goals. Increasingly, revenues are being decoupled from sales volumes so that reductions in sales volumes will

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[1] Campini, C., and L. Rondi. (2010). Incentive regulation and investment: Evidence from European energy utilities. Journal of Regulatory Economics, 38, 1-26.

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