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OCA Brief 8/7/15
Attachment 1

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

August 9, 1996

ORDER

NORTHERN UTILITIES, INC., Proposed Precedent Agreement with Granite State Gas Transmission, Inc. For LNG Storage Service

Docket No. 95-480

ORDER BOOK

NORTHERN UTILITIES, INC., Proposed Precedent Agreement with Portland Natural Gas Transmission System for Transportation Service

Docket No. 95-481

WELCH, Chairman; NUGENT and HUNT, Commissioners

I. INTRODUCTION AND SUMMARY

This proceeding is before us because Northern Utilities, Inc. (Northern or the Company), the sole local distribution company for natural gas in Maine, will lose an important source of supply in April 1998 and must find a suitable replacement supply. Northern has submitted two Precedent Agreements, one with Granite State Gas Transmission, Inc. (Granite) for storage capacity and service from a liquefied natural gas (LNG) facility in Wells, Maine, and a second with Portland Natural Gas Transmission System (PNGTS) for pipeline supply. Because both Granite and PNGTS are affiliates of Northern, both agreements require our review and approval. In addition, Northern requests that we approve ratemaking treatment and find that the arrangements are prudent.

The fundamental question of the Precedent Agreements presented by Northern for approval is whether the agreements are reasonably likely to be in the public interest. Our concerns in this matter are:

1) that Northern's current customers not be left without gas when the Portland Pipe Line lease expires and that the prices to Northern's customers remain reasonable;

2) that the opportunities for further development of Maine's natural gas infrastructure not be foreclosed; and,

3) that the citizens of Wells not be unreasonably burdened with a facility of statewide, and perhaps regional, significance.

We believe this Order accomplishes the first two goals and that the Federal Energy Regulatory Commission's (FERC's) further review of the tank and pipeline proposals is likely to adequately address the second and third concerns.

While we have been presented with a settlement agreement among some of the parties to this proceeding, we decline to approve it because it does not have sufficient breadth of support and its terms do not adequately address our concerns.

Finally, the fact that there is substantial uncertainty about which project is best over the short and long term and will most likely be available by the time of need has been vigorously disputed in this proceeding. We believe it is imperative to go forward in order to ensure that we do not jeopardize the successful completion of what we have determined to be one reasonable and prudent source of supply for Northern. Based on the record, it is likely that the LNG facility is the only source of gas that will be available to Northern's customers when the lease on the current pipeline expires and that 2 billion cubic feet (Bcf) of storage capacity is needed in the absence of other supply. We are satisfied that the long term contract for the full capacity is needed to ensure that the project will be built promptly and at the lowest available cost. We are also persuaded that there is a sufficiently good chance that any capacity that becomes excess, if and when a pipeline is built, can be sold at a high enough price to minimize, if not eliminate, the difference for ratepayers between building a 1 Bcf tank -- an option that would be inadequate prior to the arrival of other supply but optimal thereafter -- and a 2 Bcf tank, that would be optimal sooner and sub-optimal later.

We reject the Precedent Agreement between Northern and PNGTS because of the excessive supply commitment. We are not satisfied that resale or release would occur at terms sufficiently favorable to ratepayers to reasonably compensate for Northern's commitment to oversupply. We will review any amended agreement without delay, should Northern choose to submit one, but also recognize that Northern may wish to review all of its supply options before doing so. We also will review Northern's resale agreement and other contracts with Gaz Metropolitain without delay. However, we decline at this time to conclude that these contracts are in the public interest on the limited record we now have.

Finally, we require Northern to file revenue information and standards of conduct governing transactions with its affiliates for our review and invite comments from the parties regarding what future proceedings will best serve to consider appropriate revenue levels, performance based regulation, service unbundling and restructuring for Northern. We also require Northern to file an unbundling proposal with proposed tariffs by December 31, 1997.

<u>Summary</u>

Specifically, we

- reject the Stipulation joined by the Public Advocate, Northern

Utilities, Inc. (Northern) and Maritimes and Northeast Pipeline, L.L.C. (Maritimes or M&NE), filed May 28, 1996;

- approve the revised Precedent Agreement between Northern and Granite State Gas Transmission Inc. (Granite State) filed on June 27, 1996 for Liquefied Natural Gas (LNG) storage services, pursuant to 35-A M.R.S.A. §707, and find Northern's decision to enter into the agreement to be prudent at the level of current reported project costs ($50.4 million);

- reject the Precedent Agreement between Northern and the Portland Natural Gas Transmission System (PNGTS), filed April 1, 1996, for pipeline capacity because it subjects ratepayers to the costs of substantial excess capacity over the term of the contract, for which Northern's ability to mitigate through decontracting or resale is uncertain;

- determine that, subject to a review of Northern's management of its supply portfolio and excess capacity, costs of the LNG facility may be collected by Northern through the Cost of Gas Adjustment (CGA), except that the rate effect will be phased in at no more than 12% per year on the average residential bill;

- require Northern to make a modified Chapter 120 filing and to file standards of conduct governing conduct with its affiliates and alternative suppliers, both within 120 days of this order;

- invite parties to submit comments 30 days subsequent to Northern's modified Chapter 120 filing regarding the type and timing of future proceedings that should be initiated to examine the issues of performance based regulation, service unbundling, corporate restructuring, and revenues; and

- require Northern to file an unbundling tariff proposal (including transportation, load balancing, and third party merchant services) by or before December 31, 1997.

II. LEGAL STANDARDS

The Company is requesting Commission approval of two Precedent Agreements between itself and its affiliated interests to enter into long term (20-year) sales contracts for purchases of gas by Northern. Pursuant to 35-A M.R.S.A. § 707, no public utility may enter into a contract for the provision of any service from an affiliate until the Commission finds that the contract "is not adverse to the public interest" and gives the contract or arrangement its written approval. This finding is to be distinguished from the more particularized findings required of the Commission in other parts of the statute. The "not adverse to the public interest" standard must be judged in the context of the statutory section of which it is a part. 35-A M.R.S.A. § 707(3)(D) provides that Commission approval of a contract or agreement under this section "may not limit or restrict the powers of the Commission in determining and fixing any rate, fare, toll, charge, classification, schedule or joint rate as provided in this Title." The statutory language indicates that a finding under section 707 that a given affiliated transaction is "not adverse to the public interest" does not in any way restrict the Commission's ratemaking authority when dealing with the specific costs of the transaction in question.[1] For these reasons approval of these contracts under section 707 would not, in itself, provide Northern with any guarantee of the ratemaking treatment to be applied to these contracts, or constitute a review of the prudence of Northern's purchasing decisions.

Northern, however, has requested that, in addition to the finding under section 707, the Commission investigate and rule upon the prudence of its proposed agreements.

In Docket No. 84-113, Re: *Investigation of Seabrook Involvements by Maine Utilities*, the Commission adopted the following standard for prudence:

> [T]he standard we will apply is whether the utility's decision or course of conduct is one which a reasonable utility manager would have made or followed in light of

[1] For a more extensive discussion of these and other issues related to the scope of the proceeding, *See Procedural Order, re: Scope of Proceeding*, March 5, 1996.

the circumstances then existing and known or which reasonably could have been known.

This standard has several important features. First, the standard focuses on actions that a capable executive would make. To determine whether a specific decision or course of conduct satisfies the standard, several factors must be taken into account including the following:

1. Utility executives are expected to possess a high degree of specific financial and technical expertise.

2. The decision of the utility under investigation should, at a minimum, be comparable to the decision of other similarly situated utility and non-utility managers. In this regard, while the prevailing practice of the utility industry is relevant, it is not determinative. The decisions of utility executives must also be reasonable when viewed against the decision and courses of conduct of other corporations that make investment decisions of a comparable size and complexity. Thus, the fact that many other utilities relied upon certain knowledge or reached decisions similar to those reached by the utility under investigation does not by itself establish prudency.

3. The size and nature of the undertaking being reviewed must also be considered. Thus, more care should be exercised where the magnitude of the investment is disproportionately large and potentially unlimited.

4. Review of utility decisions should be made in recognition of the utility's legal obligation to provide safe, reasonable and adequate service at the lowest

possible long run cost throughout its service territory. 35-M.R.S.A. § 51.

Commission Order, April 17, 1985, at 9-10.

Northern bears the burden of proof. 35-A M.R.S.A. § 1314. The existence of a stipulation in no way lessens the utility's burden to demonstrate that the Precedent Agreements comport with the prudence standard as annunciated above. To show that the stipulation is just and reasonable, the Company must demonstrate that its Precedent Agreements, as modified or conditioned by the terms the stipulation, are each in the public interest and will result in rates that are just and reasonable to ratepayers. Although we encourage parties to work towards consensus on issues, the Commission has the obligation to independently review a stipulated result and the evidence which supports its adoption, to ensure that the overall result is in the public interest.

The Town of Wells and NO TANKS have continued in their opposition to the stipulated result reached by the other parties and raised significant issues which this Commission must address. In addition, the Office of the Public Advocate (OPA) and Maritimes raised many valid issues with regard to the Precedent Agreements. To the extent that the stipulation is presented as a means of resolving the issues in this docket, the Company and the stipulating parties must present sufficient evidence that the stipulation adequately addresses the legitimate issues raised.

III. DESCRIPTION OF THE PRECEDENT AGREEMENTS

A. Precedent Agreement with Granite

The Precedent Agreement between Granite and Northern was entered into on September 14, 1995. On June 26, 1996, Northern filed a revised Precedent Agreement which modified the original agreement's provisions regarding deliverability capacity and the proposed rate structure. In what follows we will refer to the provisions of the revised Precedent Agreement unless otherwise noted. The Precedent Agreement consists of two major sections, the Precedent Agreement itself and the LNG storage contract which is incorporated by reference. The Precedent Agreement outlines the conditions necessary before the LNG contract is entered into. The LNG storage contract itself specifies particular terms and conditions governing the provision of storage service by Granite to Northern.

Under article 1 of the agreement, Granite agrees to use its best efforts to obtain such property and other rights and regulatory approvals as may be necessary to effect the storage and deliverability services set out in the LNG storage contract. The contract requires Granite State to construct and maintain facilities sufficient to provide storage capacity for 2 million Decatherms (2 BCF) of liquefied natural gas (LNG) with a storage and deliverability capacity of 134,000 Decatherms per day (Dth/D).[2] The agreement contemplates the construction of a 2 Bcf LNG storage tank at Wells, Maine to be owned and operated by Granite.

Under article 3 of the LNG storage contract, the tank is to be the receipt and delivery point for gas supplies owned by Northern. Under the agreement, Northern assumes responsibility for the supply and transportation of gas to the LNG facility.

Article 4 of the LNG storage contract specifies the rates and charges for the storage service provided by Granite. Article 4.1 requires Northern to pay storage charges in accordance with section 4 of Granite's rate schedule LNG 1, which will be a FERC approved tariff and will reflect the full embedded cost of the LNG facility. In addition, Northern agrees to provide Granite with gas for Granite's operational requirements associated with storage and vaporization service at the facility. Under article 4.4, Granite retains the unilateral right to file for changes of rates for service pursuant to schedule LNG 1 or any other provision of its general terms and conditions of FERC's gas tariff applicable to the service being provided.

The term of the contract is anticipated to be 20 years from the date service is first provided.

Article 8.3 provides that Northern would be assessed an exit fee for stranded cost related to the recovery of the capital costs and other costs associated with the storage facility, if Northern terminates the contract prior to

[2] The original agreement of September 14, 1995 allowed maximum deliverability of only 54,640 Dth/day. For a further discussion of this change see Section VIII(C) below.

the end of the 20-year term.

B. Precedent Agreement with PNGTS

On March 12, 1996, Northern entered into a Precedent Agreement with PNGTS. The agreement requires PNGTS to place pipeline facilities in service sufficient to deliver specified quantities of natural pipeline gas from a receipt point at Jay, Vermont to delivery points in Falmouth and Wells, Maine and Newington, New Hampshire for a period of 20 years. Delivery quantities consist of 365-day base load service of 1,100 MBTU/day to Falmouth, Maine and winter service quantities (151-day service, November 1st thru March 31st) of 27,900 MMBtu/day at Falmouth, 9,000 MMBtu/day at Wells, Maine and 23,900 MMBtu/day at Newington, New Hampshire for a total winter service of 60,800 MMBtu/day. As with the LNG Precedent Agreement, Northern has the obligation to secure the quantities of gas necessary for transportation. Service under the contract will be provided in accordance with FERC approved tariffs. Schedule 2 attached to the Precedent Agreement outlines the parameters under which PNGTS intends to file with FERC for initial firm transportation rates.

The price and quantity terms of the Precedent Agreement are subject to adjustment under paragraphs 3(B)(I), (ii) and (iii) of the Precedent Agreement.[3] Paragraph 3(B)(I) provides that if PNGTS gives a discount for any mainline transportation services, Northern will be entitled for the same period of time to receive the same discount on a per MBTU basis for all the quantities shipped under the firm transportation contracts. For instance, if PNGTS discounts service under any rate schedule during the months of November through March, PNGTS must offer Northern an equal discount during the same period of time. Likewise if PNGTS discounts service in the off-peak months of April through October, Northern will be entitled to a discount equal to an imputed off-peak rate minus the rate provided to the other shipper during the same period.

Under paragraph 3(B)(ii) Northern has the right to decontract amounts that it believes are in excess of its needs if and/or when the PNGTS pipeline is fully subscribed such that PNGTS is receiving revenues that at least equal its

[3] The provisions described hereafter are only effective if approved by the FERC and only for so long as FERC does not disapprove of them.

annualized cost of service. When this occurs, Northern will be permitted to reduce its base load quantities and/or winter service quantities by an amount which does not cause PNGTS to receive revenues that are less than its cost of service. The ability to decontract is not open-ended. Northern must make a timely request (within 60 days of receiving notice that the pipeline is fully subscribed) for decontracting at such time as the conditions specified above are met or Northern will waive its future right to decontract the specific amount in question and will also lose its right to receive any discount under paragraph 3(B)(ii) for that same portion.

Paragraph 3(B)(iii) provides that all unsold capacity available during the off-peak months of April thru October on the PNGTS system will be allocated pro rata to Northern and all other long-term shippers at no additional demand charge.

Paragraph 4 provides for the termination of the agreement by either party if PNGTS has not received a certificate of public convenience and necessity from the FERC by November 1, 1998.

Paragraph 7 provides for specific penalties to be assessed against Northern in the form of reimbursement of development costs if Northern fails to fulfill its obligations under the agreement and this causes PNGTS to terminate the Precedent Agreement or abandon the development of the pipeline.

IV. ORIGINAL CRITICISMS OF NORTHERN'S PROPOSED PRECEDENT AGREEMENTS

Both M&NE and the OPA (who are parties to the Stipulation) filed testimony in opposition to approval of the Precedent Agreements, but subsequently argued for Commission approval of the Precedent Agreements as stipulating parties. Because of the objections raised by NO TANKS and the Town of Wells, and in light of the erosion of support for the stipulation among signatories, we believe that it is important to examine the arguments originally made against approval of the agreements by these parties in order to evaluate these original objections.[4] If we conclude that the original objections raised to approval of the Precedent

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[4] We are generally inclined to give greater deference in cases where there is unqualified and unanimous support for a stipulation of the contested issues.

Agreements were meritorious, we must then inquire whether the Stipulation entered into by the parties adequately addresses those concerns.

The Office of the Public Advocate filed the testimony of two witnesses, Messrs. Richard Hornby and Aleksander Rudkevich, in response to Northern's original filing. Both witnesses contended that Northern's resource acquisitions under the Precedent Agreements would unreasonably exceed the Company's anticipated needs for service to its firm customers. Mr. Hornby contended that allowing Northern to acquire such significant excess would not only cause a significant increase in cost to Northern's customers above that which would be incurred under an optimal resource acquisition, but would discourage the development of other projects. Mr. Hornby argued that by locking up Northern's firm customers for 20 years "there is no business left to give other projects wishing to serve Maine, such as the M&NE Project." Dr. Rudkevich, in his testimony, estimated that peak day capacity acquired by Northern under the Precedent Agreements would exceed the peak day needs of Northern's firm customers by 67% even assuming a colder than normal winter. Under Dr. Rudkevich's flexibility analysis, he concluded that an optimal strategy for Northern would result in costs that were 54% lower than those which would be incurred by Northern under the Precedent Agreements.

Dr. Rudkevich was skeptical regarding Northern's ability to reduce future costs through remarketing its excess capacity. In response to Northern's claim that ratepayers would receive service from a 2 Bcf tank at rates lower than LNG service from a 1 Bcf tank because of the economies of scale, Dr. Rudkevich observed that "Northern's ratepayers will benefit from this economy of scale only if Northern is able to successfully market the LNG capacity which is excess to its needs at prices equal to 40% of the embedded cost of excess capacity (40% of maximum FERC rates)." In addition, Dr. Rudkevich observed that the excess capacity on the PNGTS pipeline would be a burden to all ratepayers unless Northern were able to remarket all the excess capacity at the maximum FERC allowed rates.

In response to these perceived infirmities in the Precedent Agreement, Mr. Hornby and Dr. Rudkevich made the following recommendations regarding the appropriate ratemaking treatment and other conditions which should be imposed upon the agreements if they were approved.

Dr. Rudkevich recommended that the Commission:

> require Northern to limit the quantity of capacity it acquires under the Precedent Agreements to the level needed to meet the projected needs of firm sales service customers. Specifically, these levels are approximately 1 Bcf of LNG storage service from Granite State and 34,100 Dth/day of winter firm transportation from PNGTS.

Mr. Hornby recommended that the Commission establish a performance based regulation (PBR) mechanism in order to provide incentives to Northern to minimize its costs under the Precedent Agreements. In addition, he recommended the Commission give all Northern customers the ability to acquire supplies from third-party suppliers.

Mr. Hornby objected to the use of the CGA to pass through the costs associated with the Precedent Agreements arguing that Northern's choice of the CGA, rather than recovery, through base rates, was motivated by a desire to place 100% of the risk of these agreements on ratepayers. In particular, Mr. Hornby noted that because of the unique reconcilable nature of cost recovery under the CGA "in the absence of the threat of disallowances from prudence reviews, Northern has no direct financial incentive to keep its actual gas cost below its gas cost recovery revenues." Mr. Hornby argued that since many of the costs incurred to manage the gas portfolio are not recovered through the CGA, the incurrence of those costs by Northern would be discouraged and Northern is, in fact, given an incentive not to spend money in these areas because such expenditures simply reduce its rate of return "while any resulting savings in gas costs are flowed to sales customers."

Finally, the OPA criticized Northern for its failure to adequately evaluate the proposal for gas supply put forward by M&NE in making its resource acquisition decisions.

M&NE filed a testimony of Mr. John Webber and Mr. David F. Mackie. M&NE witnesses echoed many of the concerns raised by the OPA witnesses regarding Northern's acquisitions of significant excess capacity through the Precedent Agreement. Mr. Mackie focused his criticisms on the potential for damaging or unfairly reducing competition in the emerging gas market if Northern is permitted to acquire significant excess capacity subject to guaranteed recovery from ratepayers. Mr. Mackie claimed that such use of ratepayer guarantees is effectively a subsidy for Northern in competitive markets where the excess can be sold at any price down to variable cost in order to build market share or discourage new entry, while ratepayers guarantee the fixed cost component in rates. Mr. Mackie noted that even if there are short term benefits to gas consumers in the Maine market from such a strategy, such benefits, if any, will go to customers other than captive ratepayers who are being asked to pay the fixed costs for these projects. More generally, Mr. Mackie argued that ratepayers should not subsidize competitive ventures for regulated utilities. Mr. Mackie cited a recent annual report from the Company, where the Company apparently recognizes a distinction between projects such as PNGTS and the proposed LNG facility and its more traditional regulated local distribution company (LDC) responsibilities. Mr. Mackie suggested that Northern is attempting to use its regulated base to leverage itself into a surplus position in order to absorb new demand at retail, effectively foreclosing or stalling competition in these markets. Finally, Mr. Mackie contended that Northern did not adequately consider other resources, including the potential for Maritime's supply, when making its resource acquisition decisions. Noting the close inter-affiliate relationships between Northern, PNGTS, Bay State and the other investors in the PNGTS Project, Mr. Mackie observed apropos of Northern's excess commitment to the PNGTS Project that "the level of subscription to PNGTS appears to have been dictated by the partners of PNGTS, not Northern Utilities' market needs."

Mr. Webber's testimony concentrated primarily on alleged flaws in the optimization analysis presented by Northern in support of its resource acquisition decisions. Mr. Webber contended that the "optimization runs" presented by Northern are not in any true sense optimizations because they never compare true ratepayer costs and risks associated with the Precedent Agreements with Northern's other available options. Of the three optimization runs presented by Northern, Mr. Webber claimed that the first was forced by the programmer to select the LNG and PNGTS Projects at the levels already committed to in the Precedent Agreements. The second of Northern's runs took the average unit rates for the projects and presumed that Northern could purchase any quantity of either LNG or PNGTS gas at average unit rates. Mr. Webber's criticism of this technique was that although amounts selected by Northern's optimization program in run two were not forced, the price used in the run was unrealistic because it ignores both economies of scale and the risk of being unable to resell or remarket the excess capacity at full embedded cost. By choosing to use average unit rates in the optimization, Northern implicitly assumed that all excess can be sold or remarketed at full embedded costs. In the third run, although Northern used 80% of the cost of a 2 Bcf facility, it still modeled PNGTS at average unit costs without taking into account the excess costs incurred under the Precedent Agreement. In addition the third run was forced by the programmer to choose the LNG facility and PNGTS. Mr. Webber argued that an accurate analysis should assume resale opportunities at current market prices rather than full embedded cost and should take into account all of Northern's options including M&NE rather than relying upon an operator's predetermined decision that the LNG and the PNGTS resources should be chosen by the model. As pointed out by Mr. Webber, Northern has presented no optimization run which chose a 1 Bcf LNG facility at 80% of the cost of the 2 Bcf facility, and that, therefore, Northern's optimization runs provide no basis for determining that a 1 Bcf LNG commitment is an optimal resource acquisition for Northern.

The representatives from NO TANKS and the Town of Wells, although they did not present a witness in this proceeding, provided evidence and information to the Commission through cross examination and argument regarding their concerns with both the original Precedent Agreements and the stipulated resolution proposed by other parties. The Town of Wells and NO TANKS agreed with other parties' original criticisms that Northern's Precedent Agreements were signed without giving serious consideration to the availability of gas from other suppliers which might have satisfied Northern's needs without requiring the construction of a 2 Bcf LNG tank in Wells, Maine. In particular NO TANKS criticized the Precedent Agreements for committing ratepayers to a 20-year investment, despite the clear recognition by all parties that restructuring of the gas industry in Maine was imminent. NO TANKS argued that not only were such 20-year commitments inconsistent with the development of competition in the gas industry, but that they would in fact frustrate the development of competition in the industry or significantly reduce its benefit for captive customers because of the prior 20-year commitments to significant capacity resources. Representatives of NO TANKS emphasized to the Commission the potential availability of flexible and shorter term options such as those outlined by M&NE witness Mr. Webber in his testimony. Under cross examination, although Mr. Webber did not maintain 20-year commitments in the gas industry were per se unreasonable, he did acknowledge that the emerging gas market would undoubtedly give rise to competitive financing and other options which had the potential to be more beneficial to purchasers depending upon their need than the long-term "bullet proof" agreements signed by Northern with its affiliates in this case. As noted by Mr. Mackie;

> I don't believe that 20-year commitments for new project undertakings are required in this day and time for certainly pipeline projects and not likely for any other type of energy project. The terms and circumstances under which commitments are made in the free market are much different.

Mr. Clark, a representative of NO TANKS argued:

> We don't know what's going to happen over the next 20 years. We only know that things are going to change. That we can say with certainty. And you're tying the ratepayers to something that's not going to change and it's not appropriate. You are in the position analogous to the man who buys the finest horse and buggy in town when -- factories are starting to turn out automobiles all over America and 20 years from now everybody is going to have a car and you're going to be tied to what you decided today or what you decide in this proceeding. Twenty years is a very, very long time. You've heard a gentleman testify today, short-term contracts and flexibility can benefit the consumer, can benefit the industry, can benefit the State of Maine. If you approve this, you're turning your back on that. You're fighting the last war.

In addition, NO TANKS argued that to the extent that Northern was representing the Wells LNG facility as the most likely of the resource alternatives to be available, the Commission should consider the uncertainties surrounding the Wells LNG Project and other projects objectively. NO TANKS pointed out through cross examination that, although several of the other projects did have uncertainties associated with them, the Wells LNG Project in particular had not received any regulatory, zoning or other approvals necessary to begin construction, and that it had already been delayed for a significant amount of time because of local opposition. Although acknowledging there was likely to be opposition to other projects as well, Mr. Clark emphasized that if uncertainty surrounding other projects was to be a basis for the Commission's decision whether to approve the Wells LNG project, then the Commission should carefully consider whether the uncertainties surrounding the LNG project were, in fact, significantly different than those surrounding other projects. This point was underscored in the Joint Motion filed by NO TANKS and the Town of Wells on August 2nd, arguing that FERC's July 31 preliminary determination approving the pipeline projects on non-environmental issues significantly increases the assurance that the Maritimes' projected in-service date of November 1, 1997 is credible and that the pipeline may be available as a supply alternative to the LNG facility.

NO TANKS also raised several objections that are more pertinent to a consideration of the Stipulation and will be dealt with in a later section.

V. NORTHERN'S RESPONSE

In response to the criticisms and recommendations of the OPA's and Maritime's witnesses, Northern filed testimony of Dwight Curley, Peter Kind and John Reed.

Mr. Curley argued that claims that Northern had contracted for excess capacity were inaccurate, because in order to acquire resources necessary to service anticipated demands, Northern had no choice but to contract for the amounts in the Precedent Agreements. Mr. Curley claimed that Northern could not limit its acquisitions to theoretically optimal levels because (a) 1 Bcf capacity of LNG would be insufficient to meet Northern's needs if the PNGTS pipeline was not in service by November 1, 1998, and (b) without Northern's commitment to 60,800 Dth/day of capacity on PNGTS, the PNGTS project itself would not have been developed. Therefore, Mr. Curley contended, "Northern has contracted for the minimum capacity possible pursuant to its optimal portfolio strategy and consistent with its commitment to provide reliable supply." In addition, Mr. Curley claimed that Northern did not consider the Maritimes proposal before it entered into the Precedent Agreements because that proposal was not available at the time. Further, Northern contended that subsequent review of the M&NE Project indicated that it was not viable and therefore not a realistic option for Northern. Although Mr. Curley questioned Maritimes' motives in opposing Commission approval of the agreements, he did not respond directly to criticisms of Northern's optimization process or to concerns raised regarding the possible anti-competitive effects of oversubscription to capacity. Mr. Curley maintained that 1 Bcf of LNG would be included in Northern's optimal portfolio even after PNGTS was in service and that, even after unbundling, local distribution companies would likely be responsible for providing LNG peaking service to customers, and that provisions in the contract with PNGTS which allow for de-contracting when the pipeline is fully subscribed, will allow Northern to achieve optimal levels of capacity from this source over time.

The testimony of Northern witness Peter Kind dealt with the effect of the OPA's proposed PBR treatment on possible financing of the projects in question. For a variety of reasons, Mr. Kind argued that adoption of a PBR approach to recovery of the costs incurred under the Precedent Agreements would significantly reduce the number of investors who would be willing to back the projects and that the component of equity capital required by such investors would increase as well. This would cause a significant increase in the capital costs for the projects. Mr. Kind argued that:

> base rate recovery of Precedent Agreement obligations proposed by Mr. Hornby would be viewed by investors to significantly increase project risk and may result in the gas supply projects being non-financiable. CGA recovery, which provides for periodic tune-up of costs, will reduce financial risk and provide the credit support sought by investors.

Northern witness John Reed took issue with Mr. Hornby's suggested time table for providing customer choice, claiming that there is much work that needs to be done, and much information that needs to be gathered in order to adequately assess an appropriate transition to a competitive market. In addition, Mr. Reed disagreed with Mr. Hornby's PBR proposal on a variety of grounds. Because the OPA has effectively withdrawn the specific PBR proposal in question, and because the Examiners have not proposed such treatment, we will not further discuss PBR criticisms and issues.

In addition, Mr. Reed provided rebuttal to the testimony of John Webber of Maritimes. Specifically, Mr. Reed criticized a variety of modeling assumptions used by Mr. Webber in comparing the costs of the proposed M&NE Projects with the Wells LNG facility. Mr. Reed reiterated Northern's concern that the M&NE proposal, even if it had been properly modeled, would not be a viable option because of the concerns about the technical feasibility of the connection with the Tennessee pipeline at Dracut, Massachusetts. Though Mr. Reed provided a critique of the M&NE analysis which compared the Wells LNG Project to the proposed M&NE Phase I, he did not address the specific criticisms of the Company's own optimization runs raised by Maritimes and other witnesses.

In response to criticisms that the 20-year contract term was inappropriate, both Mr. Curley and Mr. Reed pointed to a variety of contracts in other jurisdictions for gas supply which incorporated similar terms. As stated by Mr. Reed under cross examination:

> Lots of commissions have approved 20-year Precedent Agreements for pipe line service in the last, I'd say, three or four years. California, Wisconsin, Minnesota, Iowa.
>
> . . .
>
> It may be fair to say they're becoming less common, but that's because new facilities are becoming less common. The Pacific Gas Transmission System, for example, which went into service in 1994 was all financed on 20-year contracts and it's a facility that's seven times the size of this facility; . . .

Mr. Curley also noted that:

> . . . the purchasers of the Pine Needle capacity, I believe, have signed 20-year contracts. Pine Needle is an LNG storage facility in South Carolina, Northern Carolina -- one or the other.
>
> It [Pine Needle] has executed 20-year Precedent Agreements for 3.61 Bcf, or roughly 90% of their capacity; . . .

In addition, Mr. Kind, the Company's financial witness stated:

> . . . I can tell you that I know of no large scale utility infrastructure projects that have been financed on a project finance basis without either a life of facility agreement or a long-term contract . . .

VI. ANALYSIS OF ORIGINAL CRITICISMS OF THE PRECEDENT AGREEMENTS

Northern has carried its burden to demonstrate that, with the expiration of the Portland Pipeline lease, some new supply option will be needed for Northern's system. It is clear from the evidence in the record that the possibilities of extending the Portland Pipeline lease for any significant period are small and that, under the current arrangement, terms for possible short-term extension would be financially onerous for Northern and its ratepayers. In addition, the contingency plans that would have to be implemented in the event that a replacement is not found, would require curtailment of supply to firm customers and a moratorium on new connections, neither of which, we believe, is in the public interest. Therefore, even in the absence of a Stipulation among the parties in this case, the Commission would find that Northern was acting responsibly in seeking some form of alternative supply at this time.

We are also persuaded that if the proper long-term supply option has been selected, a 20-year contract would be consistent with current industry practice. The weight of the evidence presented by the experts in this case indicates that 20-year contracts for the type of projects in question in these cases are not uncommon in the industry and can provide benefits to ratepayers through low financing costs. Even Mr. Mackie, who testified in behalf of MN&E, though believing Northern may have overlooked opportunities to contract for supplies on a shorter-term basis, acknowledged that 20-year agreements have been typical up to this point in the industry and, depending upon the resource in question, could be in ratepayer's best interest. Although the industry may be moving toward a much more competitive structure, that structure has not yet evolved and will probably not be in place prior to Northern's anticipated need for extra capacity in 1998. In such circumstances it is not unreasonable for Northern to seek to fulfill its obligation to provide needed capacity for ratepayers on its system through a long-term commitment.

To assess the risk to ratepayers of any specific contract over a 20-year period, however, the Commission must look at such a contract in the context of the developing market. While it may be reasonable for Northern to meet its capacity needs through a 20-year commitment, other terms and conditions of the contract deserve close scrutiny in light of increasing competition in the industry. We agree with Maritimes and NO TANKS that in looking at the type of capacity resources acquired, we must not hinder development of the competitive market. In this regard we believe a commitment to obligate an incumbent utility's ratepayers to support significant excess capacity for a 20-year term may slow or hinder a competitive market. Even if such a market does develop, commitments to support significant excess could deprive ratepayers of the advantages of competition by locking them into a commitment to pay for a specific supply regardless of other options.

Although Northern has offered evidence in this case that 20-year commitments are not unusual for needed capacity, they have provided no evidence or argument that it is typical industry practice for utilities to commit to 20-year contracts for capacity significantly in excess of current or anticipated needs. All parties agree in this case that the two Precedent Agreements represent capacity commitments which significantly exceed Northern's own projected firm needs over a reasonable planning horizon. Northern argues that, for a variety of practical and financial reasons, it is not possible to obtain the necessary resources without committing to significant excess capacity, and that Northern will, over time, achieve its optimal long-term mix through de-contracting and re-marketing. Northern does not dispute, however, that the two Precedent Agreements in combination are almost double the optimal capacity commitment for its anticipated needs. Therefore, although we do not believe the emergence of a competitive market makes a 20-year commitment unreasonable per se, we question whether the proposed Precedent Agreements represent the type of long-term commitment which is best suited to Northern's and its ratepayer's needs and the development of a competitive market.

In addition, the weight of the evidence in this case indicates that Northern's analysis has significantly understated the potential risk to ratepayers of such long-term commitments to excess capacity. In Northern's optimization analysis, the Company implicitly assumes that all excess capacity can be resold or de-contracted at full embedded cost.[5] Even under these assumptions, Northern's optimization model chose capacity amounts significantly lower than those contained in the Precedent Agreements as being consistent with Northern's optimal resource strategy. We agree with the criticism offered by M&NE witness Webber and others that Northern's own optimization analysis, even though it

[5] Northern's model, by choosing resources based on average costs, implicitly assumed that all excess is sold at embedded costs.

understates the risk to ratepayers, fails to support the acquisition by Northern of amounts specified in the Agreements. With regard to the LNG facility, although Northern has found a potential purchaser for the 1 Bcf which would become excess after PNGTS comes on line, that sale would not be at full embedded cost. Although Northern's witness Mr. Curley has stated his conviction that Northern would be able to re-market or de-contract excess capacity from PNGTS at full embedded costs, the weight of the expert evidence in this case is against such an assumption.

Despite Maritimes' support of the Stipulation, Mr. Mackie testified at hearing that he continued to believe that Northern would be unable to sell excess capacity at full embedded cost. Thus,

> . . . if it were just the most desirable stuff in the world, you'd think there'd be people crawling all over them to try to take it off their hands and maybe I don't know about it, but, you know, I haven't heard anything, so I'd have to say, yeah, I think they're going to have difficulty selling it at full capacity, at least short term.

Likewise, OPA witness, Rudkevich under cross examination by Mr. Morin from NO TANKS observed

> Dr. Rudkevich: . . . It's not -- probably not very difficult to sell capacity at some price, but it would be very difficult to sell at the maximum FERC rate.
>
> . . .
>
> Mr. Morin: So we can conclude it is difficult to sell excess capacity at anything that even approaches embedded cost? These numbers are 31% of FERC approved maximum rates?
>
> Dr. Rudkevich: Well, that may vary by type of capacity by region of the country and by time of the season, but on average, -- which this number -- that on average industry wide the performance of capacity release market was approximately 30% looking at the rate.

In response to Bench Oral Data Request #1, Mr. Rudkevich analyzed Northern's historical performance in capacity releases from November of 1993 to March of 1996. That analysis reveals that Northern's ability to remarket excess capacity through release has yielded rates which, on average, approximate only 19% of full embedded costs. Though the Company's success varies from resource to resource and season to season, this historical performance raises legitimate questions about the Company's ability to remarket at full embedded cost. Northern's witness Mr. Curley agreed that if Northern were unable to de-contract excess capacity, then looking at the historical performance for capacity releases is a reasonable proxy for establishing a resale price.[6]

Dr. Rudkevich estimates the annual capacity cost of 60,800 MMBtu/day capacity on PNGTS at about $11 million per year over a 7-year study period, a present value of $60.5 million over the 7-year period. This level of firm pipeline

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[6] Examiner Sipe: Assuming hypothetically that the pipeline isn't fully subscribed in a way that allows you to de-contract, which, as I understand it, is just basically give the capacity back to the pipeline, if that's a --

Mr. Curley: Yes, because other people have stepped up to take it.

Examiner Sipe: Okay. If that doesn't happen, what are your best long-term resale options for that capacity?

Mr. Curley: If that doesn't happen, then the best option is to put it on the bulletin board and release it.

Examiner Sipe: Okay, so for that scenario where it isn't -- where you're not able to de-contract, that would still be a reasonable proxy for it.

Mr. Curley: Yes, but again, that is not what we expect and haven't expected from the beginning because in this situation where you're releasing capacity, if you will, or holding capacity into a specific region such as Maine, there are no other alternatives at the present time.

capacity is not supported by Northern's resource planning exercises. The Company has said the appropriate amount of PNGTS capacity is 34,000 MMBtu/day (1,400 of which is year-round firm, the balance for winter storage gas). Northern's model has chosen a contract for 34,000 MMBtu per day based on the average rate as the best possible outcome (optimal). This would cost Northern about $6.3 million per year, or $33.8 million over the study period.

In Examiners' Request No. 4, Northern made the assumption that it would be able to sell unneeded capacity at 50% of the embedded rate. If this were possible, the result would be an annual cost of about $8.7 million per year and $47 million over the study period. This annual difference of $2.4 million above the optimal portfolio level would have to be made up by Northern's ratepayers. The 50 percent assumption, however, may still understate the risk.

OPA witness Rudkevich has provided information that shows Northern has historically only been able to release capacity at between 31% and 19% of its full embedded value. When capacity release at 31% is assumed, Northern's ratepayers must pay an additional $3.4 million per year above the optimal level. When capacity release is assumed at 19% of full embedded cost, the shortfall increases to about $4 million per year over the optimal resource portfolio.

Moreover, even Northern's stated confidence in its ability to resell or de-contract at full embedded costs is considerably tempered when confronted with the possibility of attempting to re-market or resell without a ratepayer guarantee.

As Mr. Curley stated:

> . . . it would be I believe Northern's position if this Commission decided in fact the State of Maine really didn't need the 60 million a day but needed only the 34 million a day, and therefore went ahead and made that a condition, that I believe we would have to invoke the regulatory out in order to change the Precedent Agreement; and I think it would severely affect the viability and the possibility of PNGTS going ahead.

In summary, Chairman Welch observed:

> Just so I understand it, based on my reading of the settlement agreement and testimony, you have -- Northern has confidence it would be able to secure sufficient commitments to cover the entire 60 million, notwithstanding the optimization expectations, but not enough confidence to sign the contract on its own nickel.

Although there can be no certainty in these matters regarding what the future market for capacity may look like, we believe that Northern's analysis significantly understates the risk to ratepayers of guaranteeing cost recovery for unmarketable or marginally marketable excess capacity. The risk of resale, however, affects the projects differently. With respect to the PNGTS project, under the current FERC pricing regime which allows a maximum rate of full embedded cost, ratepayers have at best a chance to break even for underwriting the downside risk of this excess on PNGTS. With respect to the LNG tank, on the other hand, because of economies of scale, Northern need not sell the additional Bcf of LNG capacity at full embedded cost for the resale of excess LNG capacity to result in an overall benefit to ratepayers.

With these considerations in mind, we will examine the Stipulation.

VII. THE STIPULATION

On May 28, 1996, the Public Advocate, the Company and Maritimes entered into a Stipulation to resolve the issues in this proceeding.

Paragraph 1 of the Stipulation states the agreement of the parties that the Precedent Agreements, as conditioned by the Stipulation are not adverse to the public interest pursuant to 35-A M.R.S.A. § 707 and that Northern's actions in entering into the agreements are prudent.

Paragraph 2 of the Stipulation obligates Northern to enter into an agreement with a purchaser for the release of one Bcf of the capacity purchased by Northern under the Precedent Agreement with Granite State. Northern intends to fulfill its obligation under paragraph 2 through an agreement reached with Gaz

Metropolitain (GMLP) whereby Northern shall sell to GMLP one Bcf of capacity from the LNG facility at a price not to exceed 64 percent of 50 percent of the total annual cost of service of the facility, which amounts to 36% less than the FERC approved rate paid by Northern. GMLP will contract with Northern for one Bcf storage capacity for a term of 20 years. Under the agreement GMLP would have an option for a 50% equity position in the Wells LNG facility to be exercised within 60 days of FERC issuance of final certificate for the facility. The purchase agreement is contingent upon construction and commencement of service on the PNGTS pipeline in order for quantities from the Wells LNG facility to be deliverable by displacement to GMLP. It is the contention of OPA and the Company that the agreement with GMLP will leave Northern ratepayers in a position to receive an optimal[7] level of LNG service, (i.e. approximately 1 Bcf), at a rate 11% less costly than had Northern built a 1 Bcf LNG facility on its own.[8]

Under paragraph 3 of the Stipulation Northern agrees to request Granite to seek the lowest long-run cost financing for the LNG facility. By a letter attached to the Stipulation, Granite acknowledges its agreement to comply

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[7] Maritimes does not believe that a 1 Bcf LNG commitment is optimal for Northern given its contention the M&NE Phase I is a better option.

[8] According to Mr. Curley, a 1 Bcf tank will cost 76% of what a 2 Bcf tank costs. So the cost ratios are:

1 Bcf/2Bcf = 76/100

The rates will reflect this cost relationship, but also the fact that the 2 Bcf costs are spread out over twice the volume. So:

1 Bcf rate/2 Bcf rate = 76/(100/2) - 76/50.

1 Bcf rate = 76X
2 Bcf rate = 50X

In effect, GMLP gets a 36% discount from the 2 Bcf rate and Northern gets a 36% markup from the 2 Bcf rate for 1 Bcf of capacity. (1.36 x 50X = 68X). This amounts to an 11% discount from 76X, the 1 Bcf rate for Northern. (.89 x 76 = 67.6) with that request.

Paragraph 4 of the Stipulation requires Northern to undertake all practicable, reasonable and prudent actions to reduce its pipeline transportation and storage capacity commitments to optimal levels. The parties acknowledged that optimal levels may change over time depending upon future demand growth or other conditions in the gas supply market.

Paragraph 5 of the Stipulation represents the agreement of the parties that Northern will recover the costs incurred pursuant to the Precedent Agreements through the cost of gas adjustment (CGA) and that, to the extent required, approval of the settlement by the Commission would constitute a waiver of PUC Chapter 430 of its rules.

Paragraph 6 provides for continuing Commission authority in CGA proceedings to review the prudence of Northern's management of its upstream capacity and to disallow any excess cost incurred because of a failure to manage such capacity in a reasonable manner. In conjunction with paragraph 1 of the Stipulation we interpret this to mean that although the initial decision to enter into the Precedent Agreements has been acknowledged by the stipulating parties to be prudent, costs for these agreements may still be disallowed if sufficient evidence is presented that Northern's management of the resources thus acquired, including its opportunities for decontracting and off system sales and capacity releases, is not prudent.

Paragraph 7 requires Northern to file by July 1, 1996 a request to modify the CGA to extend the present 90%/10% customer/company revenue arrangement which is currently applicable to net revenues from on system interruptible sales, to apply also to net revenues from off system sales, capacity releases and on system interruptible transportation. This sharing arrangement, however, will not apply to capacity acquisitions under the Precedent Agreements until after Northern reduces LNG capacity by 1 Bcf and its pipeline or underground storage capacity by 27,000 MMBtu's a day. (We interpret these provisions as essentially excluding off system sales and capacity releases for the excess capacity (amounts above optimal) under the Precedent Agreements from the 90%/10% split.) For these sales the Commission will continue to rely on regulatory review in CGA proceedings to assure best efforts by Northern to reduce its costs under these agreements.

Paragraph 8 requires Northern to cooperate in a non-discriminatory and good faith manner with third parties who apply for interconnections.

Paragraph 9 of the Stipulation requires that the impact on rates associated with the costs incurred under the Precedent Agreement to be phased in, in three steps. In the first year of the phase-in, the total bill for the average residential customer will not exceed 112% of the rate in effect for the prior 12-month period. Any cost not recovered due to that limitation would be deferred with carrying charges and recovered in the next winter's CGA subject to the same 112% limitation. In the final year of the phase in, all deferred costs (if any) with carrying charges would be recovered through the next winter's CGA rate.

Paragraph 10 of the Stipulation requires Northern to make a good faith effort to file tariffs for Commission approval to make unbundled services such as transportation, load balancing and utility third party merchant services available to all customers no sooner than November, 1997 and no later than February, 1999. The Stipulation contemplates a Commission timetable which would result in effective availability of unbundled service no later than November 1999. In addition, Northern has agreed to file on or before September 1, 1996, for approval of standards of conduct applicable to transactions with its affiliates and its conduct in relation to alternative suppliers.

Paragraph 11 requires Northern to seek to recover any cost associated with the Precedent Agreements which may become stranded in a manner which is "competitively neutral with respect to both transportation and sales customers." In addition the parties to the Stipulation agree that:

> Nothing in this Settlement will bind the PUC or any party with respect to the recovery of any stranded costs.

Based on this statement, and Northern's testimony at the June 18 hearing, the Commission is not barred from withholding full recovery of PNGTS or LNG capacity costs in rates if the associated capacity is "stranded" or excess to optimal system requirements at some future point in time. This is an important assurance, going forward, that approval of the Precedent Agreements does not tie the hands of a future Commission in dealing with then-prevailing circumstances of lost load and stranded investment.

VIII. ANALYSIS

A. The Stipulation

We now discuss whether of the proposed settlement adequately addresses the concerns raised about the original Precedent Agreements.

In its comments, NO TANKS noted that:

> Throughout the entire process the applicant has insisted that the tank and PNGTS are two separate projects. If you go forward and approve the proposed settlement, you have done what even the applicants said they didn't want to do. You have irretrievably tied these two projects together because in order for the applicant to shed the one billion feet of capacity and the proposed LNG storage tank, PNGTS must be built, not Maritimes Northeast not some unknown pipeline that no one has identified yet, PNGTS must be built to justify the construction of that tank and to make this settlement work. That's what it says on the first page.
>
> So you can talk about a level playing field, but if you have two players each proposing a pipeline and you approve this settlement, then you have thrown your weight behind PNGTS and you cannot give a fair shake to the other players.

We agree with NO TANKS that the Stipulation by its terms links these two projects in a manner which was not contemplated by the original filing in these dockets. We also agree that such a linkage has the potential to tilt the competitive playing field towards the PNGTS pipeline rather than another competing pipeline if the Commission were to approve either Precedent Agreement without a thorough and careful review of the individual merits of the two projects as compared to other individual resource options. It would clearly not be appropriate for the Commission, for instance, to approve the PNGTS Precedent Agreement simply because Northern claims that the project is necessary in order to resell 1 Bcf capacity from the Wells tank. Likewise, it would not be appropriate to approve the Granite Precedent Agreement for the LNG facility based solely upon assurances that PNGTS will be built and the contemplated resale to GMLP will occur. While it is possible that the combination of the two resources may provide a better balance for Northern's system than reliance upon either one or the other, each resource and each Precedent Agreement must stand on its own as Northern's best and least cost option for that particular type of resource to be considered to be in the public interest. This is particularly the case in light of the close inter-affiliate relationships among GMLP, Northern and Granite, which all have interests in the PNGTS pipeline either as subscribers or as owners.

Although the particular capacity release agreement between Northern and GMLP relies on the completion of the PNGTS pipeline, it is not clear that similar capacity release opportunities would not be available to Northern in the future which did not require Commission approval of an affiliated pipeline project. On the other hand, if these two projects are indeed the most economical respective resources for LNG and pipeline capacity, and if Northern's optimal resource plan contains a mix of both of these resources, then the linkage between these two projects, despite their affiliated sponsors, would be appropriate. To make such a determination, however, the Commission must address the merits of the two Precedent Agreements independently.

Although the Stipulation purports to protect Northern's ratepayers and competitors from the potential ill effects of Northern's acquisition of significant excess capacity, we question whether some of these provisions provide any substantial benefits to ratepayers beyond the current provisions of Maine law which vest jurisdiction in this Commission to ensure safe, reliable service at just and reasonable rates. For instance, paragraph 3 of the Stipulation, which requires Northern to request that Granite seek the lowest long-run cost financing for the LNG facility, does not appear to expand upon the obligation of every public utility, whether regulated by FERC or by the state, to operate in a least cost manner. Likewise, the provision of the Stipulation which reserves to the Commission the right to disallow costs in CGA proceedings which are the result of imprudent management of Northern's supply portfolio does not appear to grant the Commission (or to any other party) any additional authority or opportunity to challenge imprudent management decisions than they currently have under the present regulatory regime. Although there is some question whether a CGA proceeding, in its current form, is adequate to address the sometimes detailed supply and resource analysis necessary to make a determination of prudent management, it has always been in the Commission's discretion to disallow costs that result from imprudent management of supply portfolios where such imprudence could be demonstrated. Though we agree with the Public Advocate that there may be some value in having a clear statement in the record from Northern that it has the obligation to manage all of its resources in a prudent fashion and to pursue resale and other opportunities which could benefit ratepayers, we are not persuaded that such a statement is necessary (or even sufficient) to hold Northern to its obligations in this respect.

The issue of stranded cost recovery is another area where it is unclear whether the Stipulation provides any additional benefits to ratepayers beyond the Commission's inherit discretion to deal with the issue of stranded costs in the future in a way that best serves the public interest. Paragraph 11 of the Stipulation clearly indicates that the Commission is making no commitment to the recovery of stranded costs by making its prudence determination in this case. It is not clear, however, that a Commission determination of prudence in this case without the language contained in paragraph 11 would necessarily be determinative in addressing the stranded cost question in the future.[9] Although costs which are imprudent by definition cannot be stranded (because they are ineligible for recovery under any regulatory regime), the proportion of stranded costs which are to be recovered from ratepayers under an unbundled utility structure is a separate question which cannot be answered simply because those costs may have been prudent when originally incurred. The limits of the "protection" provided by paragraph 11 of the Stipulation were clearly articulated by the following exchange at hearing between Chairman Welch and counsel for Northern Utilities:

> Chairman Welch: There is clearly a further debate to be had down the road, perhaps sooner in electricity, but certainly down the road as to whether or not it's appropriate for a

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[9] Nor do we view the language in paragraph 8.3 of the LNG Precedent Agreement as determinative of how this Commission may ultimately determine the appropriate level of stranded costs for Northern.

Commission once having allowed costs into the rate base to then thereafter disallow them or decide they shouldn't be recovered, having labeled them stranded costs. I'm not -- I don't propose to resolve that in the next month, but --

Mr. Dexter: And that's exactly why we had that provision in Paragraph #11.

Chairman Welch: I understand that. But, so I understand it, there's nothing in this agreement that would preclude the Commission from making a finding that was otherwise lawful with respect to stranded costs.

Mr. Dexter: Thank you. That's what I was trying to say.

Though there may be some marginal value to a clear Commission statement that it has not foreclosed the question of stranded cost recovery with its prudence determination, the Company has clearly reserved to itself the right to argue in the future that failure to allow full cost recovery for prudently incurred investments is unlawful or otherwise not in the public interest. Given this, we view paragraph 11 as simply stating that all parties remain free to argue in the future whether, and to what extent, stranded cost recovery associated with the Precedent Agreements is appropriate. This does not appear to be a significant benefit to ratepayers beyond that which is available under traditional regulatory principles.

Similarly, the Stipulation provision which requires a specific timetable for Commission completion of an investigation of unbundling for Northern would clearly be within the Commission's discretion to adopt or require even in the absence of a Stipulation between the parties in this case. In its order in Docket No. 95-236 the Commission stated its intention to issue a notice of investigation into issues surrounding possible restructuring of the gas industry in Maine and other issues related to Granite's transportation rate. As a result of such an investigation the Commission could require Northern to file specific plans for unbundling its gas service if we were persuaded that such unbundling was in the public interest. While we agree that future unbundling in the industry is a relevant consideration to the type and duration of Precedent Agreements which are beneficial, it is not clear that approval of this Stipulation is necessary to allow the Commission to proceed with unbundling under whatever time frame it believes is in the public interest. Northern has long been on record as indicating its intent to file a proposal for restructuring its services in Maine.

Although it is clear that various parties place significant weight on certain of these provisions as motivating factors for their own willingness to agree to the terms of the Stipulation, the individual motivations of parties do not necessarily translate into direct benefits to ratepayers which could not be achieved absent the Stipulation. For these reasons, though we do not have any particular objection to many of these terms, we are not persuaded that they provide a firm basis for granting approval to the Precedent Agreements to the extent that we find those agreements to be adverse to the public interest. More importantly, we believe it is not necessary to approve the Stipulation in order to secure these benefits for ratepayers.

Other provisions of the Stipulation represent concessions by Northern regarding future litigating positions or strategies which, though they may have benefits to ratepayers if adopted, do not require acceptance of the Stipulation by the Commission in order for the benefits sought to be achieved. We believe, for instance, that the recommendation that bill impacts resulting from the Precedent Agreements should be smoothed and implemented over a 3-year period is preferable to a one time increase for the entire amount represented by these projects. Absent the Stipulation it would clearly be Northern's right to request that the Commission not smooth the necessary rate increase. However, although Northern might propose a one time increase, we would be extremely unlikely to approve one. In the instant case we are inclined to require some smoothing of the rate increase necessary to fund project costs in order to mitigate the effects of rate shock.

Likewise, with the Company's agreement to request recovery of stranded costs in a manner which is competitively neutral. As we understand this provision, the Commission is not being asked to bind itself to require recovery of stranded costs in a competitively neutral fashion, but rather, Northern is agreeing that it will not request recovery in a certain manner. Absent the Stipulation, Northern would clearly have the option to request that stranded costs which result from unbundling should be recovered in any fashion they believed beneficial to the Company. While this might increase the likelihood that costs would be recovered in a non-competitively neutral manner, it would not ensure such a result. Nor does the Stipulation provide complete assurance to captive ratepayers that the Commission on its own may not determine that recovery of stranded costs is best effectuated through a rate recovery mechanism which departs from one specifically designed to be competitively neutral.

While we share the Public Advocate's concerns both for rate stability and equity in stranded cost recovery, we do not believe that acceptance of this Stipulation, with its other possibly undesirable effects upon ratepayers, is the best way to achieve those objectives. Moreover, approval of the Stipulation, which would commit Northern to what is in our view substantial and unnecessarily large amounts of excess capacity, may, in fact, exacerbate the stranded cost recovery problem by unnecessarily increasing the amount of potentially stranded investment.

Because we do not believe these terms provide any additional authority or opportunity to the Commission to protect ratepayers from the cost of excess capacity, we do not believe they represent a substantial improvement over the Precedent Agreements as originally filed. Although the Commission has always had the authority to disallow costs incurred by imprudent management of a utility's resource portfolio, this does not provide justification for allowing acquisition of substantial excess capacity, and it does not make such acquisitions prudent. Ratepayers cannot be protected from the costs of such excess capacity if Northern, despite its best efforts, is simply unable to remarket or resell such capacity at reasonable prices. The best protection for ratepayers is to require utilities to plan their resource portfolios in a manner which avoids the unnecessary acquisition of substantial excess in the first place. We are not persuaded by the evidence in this case that the combination of these two Precedent Agreements is the long-run least cost resource option available to Northern.

B. Need for Further Proceedings to Evaluate New Filings

The final hearing in this case was held on June 18, 1996. On June 21, 1996, the FERC dismissed without prejudice Granite State's application for a Certificate of Public Convenience and Necessity for the Well's LNG Project. In its letter of dismissal FERC cited Granite's stated intention to use the facility as a peak-shaving facility after interconnection with PNGTS as a change in the intended use of the facility requiring further evidence and information to be put before the FERC. On June 27, 1996, Northern executed and filed with the Commission a revised Precedent Agreement for LNG services with Granite which included changed maximum deliverability capacity and a modified rate structure. On July 1, 1996, in accordance with FERC's order, Granite revised its filing for a Certificate of Public Convenience and Necessity for the Wells LNG facility before the FERC. On July 5, 1996, Northern filed with the Commission its agreement with GMLP for the resale of 1 Bcf capacity and 100,000 Dth/day deliverability from the Wells LNG tank to commence after the in service date of PNGTS.[10]

The Town of Wells, NO TANKS and M&NE have argued that this series of events has fundamentally changed the substantive issues before the Commission in this docket and that, therefore, the Commission should reopen the evidentiary record in these proceedings, permit further discovery, and conduct further evidentiary hearings in order to determine whether the Precedent Agreements are in the public interest and represent prudent resource acquisitions by Northern. In particular, NO TANKS argues that the revised Precedent Agreement and the new emphasis of the project as a peakshaving facility reflects a different project, one that is no longer needed or appropriate and should be rejected. In the alternative, M&NE argues this Commission should approve the settlement agreement based on the original Precedent Agreement between Northern and Granite. For the reasons stated more fully below, we believe further evidentiary hearings or discovery are not necessary in this case, and that the Commission has sufficient information and evidence before it in this record to determine the advisability and prudence of the current Precedent Agreements in this case under the existing schedule.

1. <u>FERC Activity: Dismissal and Granite's Refiled LNG Project Application</u>

As noted above, on June 21, 1996 the Director of Pipeline Regulation at FERC dismissed without prejudice Granite's application for proposed LNG facility due to his perception that the purpose of the proposed project had

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[10] Northern also filed two additional agreements between Granite State and GMLP: an Option Agreement to allow GMLP to acquire up to 50% equity interest in the LNG facility and a Liquefaction Option Agreement by which the future construction of liquefaction capability may be requested by GMLP.

changed from a base load supply to a peaking facility. Granite reapplied on July 1, 1996, to reflect this change in the project. Some parties have argued that these changes are substantial, while others maintain that they are insignificant. We will address these changes to evaluate the extent of the impact that recent events and the revised Precedent Agreement has on this Commission's determination of the issues in these dockets. We will begin with the revised FERC filing.

First, it is apparent upon review of Granite's application to the FERC that the physical and engineering aspects of its proposed facility at Wells are identical to those proposed earlier. The design and siting of the facility as requested by Granite have not changed from the original FERC application. Maritimes and NO TANKS argued that the change to a peaking facility has important implications for the need, design and siting of the facility. However, whether or not the design and siting of that facility are appropriate is not an issue which is before this Commission.[11]

[11] As stated in our order on the scope of the issues in this case issued on March 5, 1996:

> . . . We have reviewed the memorandum of the parties and conclude that Commission investigation of issues surrounding zoning and the environmental impacts of the LNG facility and proposed pipeline are beyond the scope of the Commission's review in this case. The Commission is a body of limited statutory authority. This Commission does not possess jurisdiction to review and approve the citing (sic) of the LNG facility. More importantly, even if we possessed such jurisdiction, the issues before the Commission in this case are limited to the question of whether or not it would be adverse to the public interest to allow Northern to enter into an extended contract for service from such facilities *if* and/or when they are ever constructed. If environmental or other considerations foreclose construction of this facility as currently planned, the Commission's ruling in this case would be largely mooted. If, on the other hand, these facilities are constructed, it will be because the appropriate public bodies have already determined

The changes in Granite's filing at FERC were made to recast the main purpose of the project as a peaking facility rather than a base load supply for Northern. According to Granite, this was done to reflect the increased likelihood that a pipeline supply (PNGTS) will come on line by November 1, 1998.[12] Granite noted in its application that, although FERC required Granite to file tariffs suitable for a peaking facility, the facility may still be required for use as a base load supply either in the short term if there are delays in the pipeline projects, or for an indefinite term in the event there is no alternative pipeline supply.

In addition, in its refiling Granite now proposes a different rate structure, a single deliverability charge in place of a combination of capacity and deliverability charges. Granite states that this change is consistent with a recent FERC decision in *Pine Needle LNG Company, LLC, Transcontinental Gas Pipeline Corporation,* Docket No.'s CP 96-52-000 and CP 96-134-000 (April 30, 1996), but has not explained why it views this change to be preferable to its original proposal.[13] However, though the form of the rate schedule may have been changed, we expect the rates finally approved by the FERC, in whatever form, will reflect FERC's long held policy of pricing at full, embedded cost. Because the design and siting have not changed, we do not expect the change in the form of the rate schedule to affect the ultimate cost to Northern under the

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> that the facilities are environmentally and otherwise in the public interest, in which case this Commission would have no authority to overrule the findings of the FERC or any other court of competent jurisdiction in matters of zoning or environmental impact.

Commission Order, Re: Scope of Proceeding, Mar. 5, 1996 at 7.

[12] FERC and all parties are also aware that the Maritime's pipeline has a projected in-service date of November 1, 1997.

[13] The current LNG tariffs submitted to FERC also include a "primary" rate schedule that was 54,600Dth deliverability capacity in billing determinants, and an "alternate" schedule that uses 134,000Dth of deliverability capacity as the billing determinants to divide fixed costs and develop a unit rate.

Precedent Agreement.[14]

For these reasons, we do not believe the fundamental issues before this Commission have changed. The question still remains if and/or when an LNG facility is ever constructed in Wells, Maine, are the terms of the Precedent Agreement before this Commission just, reasonable and in the public interest? If the Wells facility is not approved by the FERC, then Northern will have to make some alternative arrangement for supply. Additionally, if the costs of the LNG facility change substantially because of modifications ordered by FERC, Northern will have to request further prudence review by this Commission of its decision to enter into the Precedent Agreement. There is an entire range of outcomes that might require Northern or this Commission to revisit the issue of an appropriate supply for this utility, including the failure of the LNG facility to receive necessary local zoning permits. Such uncertainties surround every project that has been discussed in this case. That is not a reason, however, for this Commission to rule preemptively that the Precedent Agreement with Granite is adverse to the public interest, or to further postpone our approval of a project which we believe will benefit ratepayers.

Maritimes and NO TANKS argue that this Commission should delay its decision in this case because of statements by the FERC and Northern that the purpose of the facility has changed since Granite's original FERC application. The FERC has expressed its concern that Northern's original application was for a base load facility and that the current record indicates that the facility is also intended to be used in conjunction with PNGTS as a peak shaving facility. While this information may provide a change in the particulars of this project as reported to FERC, it is certainly not new in terms of the litigation in this case.[15] The arguments of the parties in this case have focused heavily on the evidence that Northern's commitment to 2 Bcf of LNG capacity was not optimal (or may even be unnecessary), because pipeline capacity would become available in the future. The parties have provided this Commission with an

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[14]As noted below, a change in rate schedule may affect the way costs are assigned under the resale agreement with GMLP depending upon how the output of the facility is allocated between GMLP and Northern.

[15] In fact, FERC's action was taken after receipt of information developed in our proceeding, such as the settlement agreement and contracts with Granite.

estimate of what the optimal mix of LNG peaking capacity in Northern's resource portfolio would be when further pipeline resources become available and these issues have been explored through discovery and hearings.

In its supplemental brief of July 10, 1996, Maritimes makes the following argument:

> The July 1 filing at the FERC inextricably links the LNG Facility and PNGTS and has restructured the LNG Facility to facilitate the GMLP transaction. To accomplish this, the entire nature of the Wells LNG Project has been changed. The original rationale of the LNG Plant was to provide Northern Utilities with a source of supply upon the expiration of the Portland Pipeline Lease in 1998. The certification and construction of the LNG Facility was not originally made dependent on the certification and construction of PNGTS. The new purpose of the Wells LNG Project is to provide a peaking capability linked to PNGTS. Granite State is no longer presenting the LNG Facility as a stand alone project to be separately certificated and built. This linkage and interdependency, which did not exist under the Precedent Agreements that were in effect at the time the Settlement was executed, could be viewed as an attempt by Bay State to use the threat of the termination of the Portland Lease to get both PNGTS and its restructured LNG Facility approved by both the PUC and presumably the FERC. Whatever the motive for this new, direct linkage, its is contrary to the terms of the Settlement and should not be approved.

While it is true that Maritimes, as a competitor, did not have access to this information until Granite made its revised filing at FERC on July 1, 1996, we note that the resale of a portion of the capacity of the LNG facility has been an integral part of the settlement (signed by Maritimes) in this case since it was first introduced by the parties. As a general matter, the parties have had ample opportunity to comment on the linkage between PNGTS and the LNG facility in this case and have spent considerable time doing so. Maritimes was aware of the linkage between the sale of excess 1 Bcf from the LNG facility and the PNGTS pipeline, although not the specific terms of the GMLP transaction, when it signed the settlement agreement. We acknowledge that Maritimes reserved the right to review the terms of the sales agreement at the time that agreement was finalized and that it did not know the resale would be linked to deliveries to GMLP over PNGTS and involve greater vaporization capacity until near the briefing deadline. But the general outline of the GMLP transaction and the necessity of that transaction's being completed by a linkage with the PNGTS project, were known to the Commission Advisory Staff, the Public Advocate, the Town of Wells and NO TANKS during the original discussions and evaluation of the stipulation. Maritimes is well within its procedural and substantive rights upon review of the consummated resale agreement, and in view of a subsequently revised Precedent Agreement to which it objects, to withdraw its support for the stipulation. Such a change of position by a party is, however, not a substantive change in the evidence before the Commission. Moreover, the fact that Maritimes may have changed its position regarding the settlement agreement does not, of itself, create any additional procedural or substantive rights to further hearing on these issues for Maritimes or any other party.[16]

The essential outlines of the GMLP transaction have been known to responsible and competent parties and been subject to comment, discovery and cross-examination in this docket. That Maritimes, a direct competitor of the proposed PNGTS pipeline and the Wells LNG Project, was not given access to confidential information regarding this transaction until the deal had been finalized does not make the record before the

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[16]As we observed in our order granting intervention to PNGTS:

> Though all of these parties have a financial interest in the outcome of these proceedings, protection (or furtherance) of these private interests is not the objective of either the prudence review process for utility resource acquisition decisions or the affiliated interest review process. Rather, the primary objective of the review in this case is to assure that the utility's resource acquisition decisions are prudent and comport with least cost supply principles.

Procedural and Protective Order, May 3, 1996 at 2.

Commission on these issues inadequate.

We note that Maritimes was granted intervention in this case as a matter of Commission discretion because we believed that Maritimes could provide the Commission useful information regarding the potential for the development of the competitive gas market in the state. Although we have always viewed anti-competitive issues as of secondary importance to the primary inquiry in this case,[17] Maritimes has provided much useful information which has been instrumental in our evaluation of the issues. We acknowledge, however, that because no party had access to the finalized terms of this Agreement until July 5, 1996, some review is appropriate to assure that the final terms are consistent with the general outline provided by the parties and do not contain provisions which materially affect the value of Northern's Precedent Agreements to ratepayers. Among the revisions in the FERC filing and revised LNG Precedent Agreement are modifications to the terms of deliverability capacity and rate structure which require at least some consideration herein and some additional information in the record. For this reason the Examiners provided an opportunity for supplemental briefing of these issues and issued Bench Data Request #5.

Upon review of those supplemental filings and Northern's responses to Bench Data Request #5, and for the reasons stated more fully below, we do not view the GMLP transaction in conjunction with the revised Precedent Agreement as presenting substantially new facts or issues related to the primary objective of the review in this case, which is to determine whether Northern's resource acquisition decisions are prudent and comport with least cost supply principles. Though the details of the transaction between GMLP and Northern may affect the future financial interests of Maritimes in a way they believe is undesirable, we do not believe those terms substantially alter the respective benefits to ratepayers from the proposed Precedent Agreements in a fashion which requires a further evidentiary record to be established for purposes of our decision here. As discussed further below, however, we will have further proceedings to provide an opportunity for parties to comment on the proposed

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[17] In our order delineating the scope of this proceeding issued on March 5, 1996, we expressed our concerns that discovery and litigation of these issues should not be overdone "in light of the secondary importance of these issues to the Commission's determination on the merits." *March 5 Order at 8.*

GMLP transaction, and possibly to develop any additional record that is necessary, before granting §707 approval.

Further, we note that our decision in this case effectively decouples the Wells LNG project from the PNGTS project. We find that whether or not the PNGTS project is eventually built, the Wells LNG project represents a prudent resource acquisition for Northern. Likewise, on the basis of the evidence in this record we find that the commitment to PNGTS is not reasonable at this time at the levels requested by the Company. Therefore, our findings in this case are not significantly influenced by the details of the GMLP transaction which links these two projects.[18]

Since the inception of this case there has been a parallel proceeding before the FERC regarding Granite State's proposed LNG project in Wells, Maine. The outcome of that proceeding has always been subject to uncertainty both with regard to whether or not the project proposed by Granite State would be approved by FERC and, if approved, whether modifications in the project would be required by the FERC. FERC's dismissal without prejudice of Granite's application and Granite's subsequent refiling of its application with supplemental information for the FERC, has not changed this situation. It is still unclear whether or not the FERC will approve the LNG project or will require changes to the project which would affect its price. These uncertainties are simply intractable unless this Commission is content to simply wait and see what FERC will do before deciding this case. Moreover, this dilemma is compounded by the fact that these uncertainties also exist with respect to both the PNGTS and Maritimes pipeline proposals now pending before FERC.

We have considered the objections of NO TANKS and Maritimes to considering the revised Precedent Agreement without further procedure, and have determined that it is not necessary for a ruling on the issues before us.

2. Revised Precedent Agreement with Granite

Although the physical facility proposed by Granite State before FERC has not changed, the Precedent Agreement under which Northern will buy

[18] As noted further in this Report, the Commission is not engaged in a review of the prudence of the GMLP transaction in this docket.

the output of the facility from Granite has been revised. The single revision made to the Precedent Agreement at issue in this case is to increase Northern's entitlement to vaporization capacity from 54,000 MMBtu/day to 134,000 MMBtu/day upon the completion of PNGTS at no added expense to Northern. On its face, therefore, Northern is getting a better deal for the same money than under the original Precedent Agreement. However, the linkage to the in-service date of PNGTS specifically and the terms of Northern's Agreement with GMLP for 100,000 Dth make it clear that the benefit of this revision does not inure to Northern. Rather, in conjunction with the GMLP resale, it is simply a pass through arrangement which ultimately reduces Northern's maximum deliverability entitlement to 34,000Dth. This pass through is not a part of the precedent agreement proper, however, but is a separate resale agreement which we will address hereafter. Even if the pass through itself was determined not to be in the public interest, the Company could still benefit from the increased deliverability under the Precedent Agreement for future resale arrangements.

This change in deliverability is not inconsistent with the stated capabilities of the facility as originally filed by Northern. As described by Mr. Curley in his prefiled testimony, the total installed vaporization capacity at the LNG facility would be 136,000 MMBtu/day. Until a pipeline is built, however, Northern would have been unable to utilize the full vaporization of the facility because of existing pipeline take-away capabilities. Under these circumstances the maximum deliverability from the facility would have been physically limited to the 54,000 MMBtu/day contracted under the original Precedent Agreement. The additional vaporization capabilities of the LNG facility were designed as a back-up to ensure deliverability in the event that the first line vaporization capability was for some reason disabled. After PNGTS comes on-line, however, the full 136,000 MMBtu/day of deliverability is available because pipeline capacity will exist to facilitate take-away of that amount. In addition, it is assumed that pipeline supplies could provide back up services.

While the original Precedent Agreement did not contain the reservation to Northern of the full vaporization capacity and deliverability at the time PNGTS (or another pipeline) became available, the facility as proposed obviously had such capability (as well as a high-pressure pipeline) from the start. Moreover, it would be of even more value to Northern's ratepayers if the Precedent Agreement were worded more broadly to allow the expanded deliverability upon the availability of any pipeline and we would prefer to have this

Precedent Agreement worded that way. In fact, we have some concerns that the current restriction may limit Northern's resale options in the event that another pipeline (not PNGTS) comes on-line. We will consider this limitation in future CGA reviews of Northern's portfolio management and will require Northern to justify why it may or may not have the greater deliverability if a non-affiliated pipeline becomes available. Yet, because we believe the original 2 Bcf facility represented a reasonable source from which Northern would receive service under the Precedent Agreement, and ratepayers will not be worse off under an agreement which allows Northern greater access to the full potential of the facility at the time PNGTS comes on-line, we are inclined to view this modification, in itself, as beneficial to Northern. We will therefore not require further investigation of this particular modification.

The purpose of the Commission's investigation in this case is to ensure that Northern's resource acquisition decisions are in ratepayers' interests and comport with the principles of least cost planning. If the prior Precedent Agreement satisfied this criterion, then it is academic to ask whether a Precedent Agreement which provides greater benefit to Northern for the same cost would also satisfy that criterion. For these reasons we do not believe there is a need to re-open the record for additional evidence on these issues.

3. Resale to GMLP

As noted previously, the general outline of the transaction proposed between Northern Utilities and GMLP has been available to the parties (other than M&NE) since the settlement was first presented to the Commission on May 23, 1996. Although the Agreement was not finalized in all detail until July 5th, its general purpose and terms have been the topic of discovery and discussion at both technical conferences and hearings. The final capacity release agreement reached between Northern and GMLP is generally consistent with the parameters outlined at hearing and in technical conferences.

Because, under the original Precedent Agreement, Northern did not have the right to the full deliverability capacity of the facility after PNGTS came on-line, neither other parties nor the Commission Advisory Staff could have foreseen that the deliverability quantities in the GMLP agreement would be at the levels contemplated by the final resale agreement. That these specific levels were not foreseen, however, does not necessarily mean that they raise novel or different issues with regard to protecting ratepayers' interests and assuring that Northern's resource acquisitions are prudent and comport with least cost planning. The general purpose of the resale agreement as presented by the parties was, as noted by the Public Advocate:

> The release of 1 Bcf of LNG capacity to a third party at a 36% discount of the full embedded cost to be reflected in a FERC approved rate.

So long as that continues to be true and Northern's ratepayers continue to receive sufficient benefits from the facility to meet their optimal supply requirements, the arrangements are reasonable and in the ratepayers' interests. We concur with the Public Advocate's assessment of the Agreement contained in his supplemental brief:

> It is apparent that Northern's ratepayers would be no worse off if Northern increases vaporization capacity to 134,000 MMBtu/day and makes available 100,000 MMBtu/day to GMLP. Regardless of those events, Northern's customers will pay through CGA rates the embedded costs of one half of the 2 Bcf tank plus 36% of the embedded costs of the other half, or 68% of the embedded costs of the LNG project. After PNGTS provides service, Northern's customers continue to be assured of a peak-shaving gas supply from 1 Bcf of capacity with deliverability of 34,000 MMBtu/day,volumes that are sufficient to meet Northern's projected design day peak demand.

The capacity release agreement would also enable Northern's ratepayers to acquire the assurance of a 2 Bcf supply until such time as a pipeline supply came on-line and, thereafter, permit Northern's ratepayers to receive service from a 1 Bcf source at a rate which will be 11% less than if Northern had built or contracted for services from a stand-alone 1 Bcf facility. The GMLP resale agreement continues to satisfy these conditions. In this regard the final agreement between GMLP and Northern is consistent with the achievement of the benefits for which it was presented to the Commission in the first instance.

NO TANKS and the Town of Wells, however, have argued that the resale agreement with GMLP is an affiliated interest transaction under 35-A

M.R.S.A. § 707 and that it therefore requires Commission approval.[19] We are inclined to agree, and conclude that the parties are entitled to a more thorough review before we grant such approval. There are several issues that should be explored before making such a determination. The finalized agreement has only been available since July 5, 1996 and there is no evidence in the record at this time which would allow the Commission to establish with reasonable certainty that the capacity and the deliverability provisions of the GMLP resale are preferable to other resale opportunities that might be available or that they are consistent with industry practice. Although there is a great deal of information in the record as to Northern's success in selling capacity through its capacity release program, it is unclear at the present time the value to be assigned to the deliverability requirements of the contract. In addition, the record has not been developed with regard to any possible changes in the cost allocation between Northern and GMLP which may result from the new tariff structure filed with FERC.

The Company has provided useful information on some of these issues which may provide reasonable assurance that the GMLP transaction would provide benefits to ratepayers. This information, however, while arguably sufficient to meet the Company's limited burden under § 707, has not been subject to scrutiny by the other interested parties and has only been available to the Commission Staff since July 16, 1996. A utility seeking prudence protection from this Commission has a high burden of both production and persuasion because such a ruling generally forecloses future challenge of expenses by other parties or this Commission. The current record is insufficient for a finding on the prudence of the GMLP resale at this time.[20] However, because we have not approved the Precedent Agreement with PNGTS, and because the agreement with GMLP is contingent upon the completion of the PNGTS project, we do not believe

[19] There has been no explicit request for approval of any of the three agreements with GMLP, nor any indication from Northern or Granite whether review and approval of this Commission may be required under 35-A M.R.S.A. § 707-708 or any other provision of Maine law.

[20] We emphasize that our review of the information presented in this record and in response to Examiners' Data Request #5 does not reveal any prima facie reason for believing the GMLP transaction is imprudent. This, however, is not the standard for a finding of prudence.

any delay in approving the GMLP agreement, if it is meritorious, will harm the interests of any party or the ratepayers.

We will thus, review the capacity release agreement in a subsequent proceeding if Northern seeks approval for it. We note that because the arrangement is contingent on PNGTS's coming on-line in 1998 or 1999, there is ample time to conduct our review. Moreover, there is a significant level of uncertainty about whether the conditions precedent for the transaction, and thus this particular transaction, will ever come to pass.

C. Precedent Agreement with Granite

We conclude that the record in this case indicates that, with or without completion of the PNGTS project, the proposed LNG facility represents a prudent long-term resource acquisition for Northern.[21] If, in the future, PNGTS does become available, we believe that the evidence demonstrates (and the GMLP agreement would allow) economical use of the Wells LNG facility for peak-shaving service. As the OPA observed,

> This flexibility in the operational use of the Wells facility represents a decided benefit for Northern's ratepayers in not being locked in for the indefinite payment of the fixed costs of either type of facility. Ratepayers receive what is expected to be low-cost insurance against gas supply disruptions upon the expiration of the Portland Pipe Line lease prior to PNGTS startup and thereafter receive the benefits of operating the Wells LNG facility as a peaking resource i.e. avoiding the necessity of contracting for long-term pipeline gas supply during those days of the year that gas demand hits peak levels.

We believe that the evidence in this case demonstrates that, with the pipeline supply available, Northern's optimal resource mix contains approximately .9 Bcf of LNG. If PNGTS does come on-line, the GMLP resale agreement (if

[21]Whether the GMLP resale occurs or not, we expect Northern to be diligent in its efforts to sell the excess capacity of the LNG facility and will review this issue in future CGA proceedings.

ultimately approved) would allow Northern to reduce its capacity commitment to approximately this level. Even in the absence of PNGTS, however, Northern may have other opportunities for resale or release of this capacity. The GMLP agreement itself is evidence that sale of the 1 Bcf capacity that will not be needed to serve Northern's native load when a pipeline supply becomes available can likely be accomplished at a price that minimizes or eliminates the financial impact on Northern and its customers of building a 2 Bcf, rather than a 1 Bcf, tank. Because of economies of scale, such resale opportunities for excess from the Wells facility may, as the GMLP deal demonstrates, provide real benefits to ratepayers by reducing overall costs. Moreover, in the event that no new pipeline supply becomes available, we believe that the weight of the evidence in this case supports the conclusion that a 2 Bcf LNG commitment - even without the prospect of resale of capacity - would be a prudent resource acquisition for the Company at this time.

The expiration of the Portland pipeline lease requires the Company either to obtain additional supplies or engage in a contingency plan involving a moratorium on new connections and curtailment of service to certain firm load customers. We do not believe that the latter option is in the public interest. The timing of the pipeline lease expiration makes it imperative that the Company obtain some additional resource option prior to mid 1998. We agree with NO TANKS and the Town of Wells that there is no certainty the Wells LNG Project, even if approved by this Commission, will be available for service within this time frame. Yet rejecting the Wells LNG Precedent Agreement on the grounds of such uncertainty would do little more than transform such concerns into self-fulfilling prophecies. Clearly if the Commission does not approve Northern's acquisition of this resource, it will not be available to Northern's ratepayers within the needed time frame. NO TANKS and the Town of Wells have argued that the pipeline projects are better sources of supply and are just as likely to be in service by the time of need, November 1998. We acknowledge that there is no certainty, even with our approval here, that the tank will be built. However, there are also great uncertainties surrounding other proposed resources and projects and it is entirely possible that the pipelines will confront resistance and obstacles that could delay, perhaps indefinitely, their construction. We must remain focussed on acting in a manner that will help to ensure that a gas supply will be available at just and reasonable rates. We are persuaded that the Wells LNG facility has a reasonable opportunity to be on-line within the required time frame and will provide benefits to ratepayers in the form of needed protection from possible gas supply shortages.[22]

We decline to reject this arrangement on the basis that a better project may become available in the future. The evidence in this case has not demonstrated that the Wells LNG facility is the only possible option which could be available at this time, yet we believe that sufficient evidence has been presented to demonstrate that it is a reasonable option in keeping with the standard of care and expertise which is expected to be exercised by prudent utility management. Although it is possible that sufficient pipeline capacity could be on-line prior to the expiration of the Portland pipeline lease to allow Northern to satisfy its requirements with only 1 Bcf of LNG, or to not require LNG supply at all, given the consequences of a failure to have adequate supply on hand, we believe it is a prudent management decision to acquire sufficient LNG capacity to protect against the possibility that pipeline supply may not be available in a timely fashion.

In addition, we believe that the preponderance of the evidence in this case demonstrates that a 2 Bcf commitment is reasonable in the interim between the expiration of the Portland pipeline lease and the possible or projected on-line date of various pipeline resources. As stated by the Public Advocate, "although Northern's optimal peaking resource requirements post-PNGTS are estimated at .9 Bcf, prior to the on-line date of PNGTS deliveries no less than 2 Bcf of Wells LNG capacity is required as replacement capacity for the 36,675 Decatherms/day currently provided over the Portland pipeline." Mr. Curley echoed this statement at hearing:

> One Bcf on a continuing basis is an optimal portfolio if you also have 34 million a day on PNGTS. If you don't have PNGTS, then you need a whole lot more than that - you need 2 Bcf.

Consequently, the facility has the capacity to serve Northern in two ways, both of which appear to be valid and valuable to ratepayers.

We therefore approve the Precedent Agreement between Northern and Granite, find that Precedent Agreement is not adverse to the public interest

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[22]Of the three primary project proposals, a draft environment impact statement has been completed on only the LNG plant.

pursuant to 35-A M.R.S.A. § 707, and that the agreement represents a prudent resource acquisition by the Company.[23]

D. Cost Recovery - Rate Treatment

Having determined that the Precedent Agreement with Granite represents a prudent resource acquisition for the Company we must consider how the costs associated with that Agreement are to be recovered in rates.

Northern has proposed that the costs associated with the LNG facility in Wells and the PNGTS pipeline be recovered through the CGA mechanism. The Company asserts that this method of recovery will allow Granite to minimize its financing costs and permit it to pass those savings on to Northern and its customers. Northern presented a witness (Mr. Peter Kind) who testified that lenders would look at the likelihood of cost recovery when deciding whether and at what price to lend money for project financing. Project financing occurs when the anticipated revenues from a particular facility are used to support the debt service requirements of the project. Lenders will look at the borrowers ability to repay the loan and the associated interest.

Under the terms of the Precedent Agreement with Granite, Northern will assume responsibility for all of the costs of the LNG facility. Northern asserts that it will be able to relieve itself of any over-capacity that may exist by de-contracting (i.e., giving back some of its capacity obligation to the owner of the facility) or by reselling a piece of its own entitlement. Nevertheless, any contractual obligations that cannot be recouped through resale arrangements would be recovered through Northern's CGA mechanism, which assures full recovery of costs.

According to Chapter 43 of the Commission's Rules, the CGA mechanism is designed to recover changes in a gas utility's cost of gas between base rate cases. Its purpose is to avoid long, frequent, and expensive base rate proceedings while allowing the company to be kept whole for variations in the

[23]While we find that the Precedent Agreement is prudent, we do so based on the estimate of the cost of the LNG facility presented by Granite and Northern in this case. We make no finding here concerning the prudence of LNG facility costs charged to Northern in excess of that $50.4 million estimate.

price it pays for the gas which it sells to its end user customers. The costs are fully reconciled and a working capital allowance is included in the reconciled amount charged to rate payers. Section 1. D. defines the costs that are allowed to be included in the CGA amount. It specifically excludes "storage costs, or other non gas-related expenses incurred by the gas utility." In recent years Northern has been permitted to include some storage costs in the CGA on the theory that it is able to balance storage of gas with spot purchases in order to minimize the overall cost of gas.

While we have concluded that CGA recovery of these costs should be permitted, we do so only after satisfying ourselves that the burdens thus imposed are outweighed by the benefits. Turning first to the burdens, we believe that reconcilable recovery mechanisms, such as the CGA, provide little incentive for the utility to be anything more than nominally efficient in obtaining the lowest cost of gas available. The utility earns no profit on the gas, and purchasing practices and the resulting costs receive only a limited amount of scrutiny. The review of CGA filings is a limited one, both in terms of scope and timing. A gas purchasing practice would have to be quite obviously imprudent for a red flag to be raised, given the time constraints of the CGA filings. From a practical standpoint, a utility must merely demonstrate that its practices are "reasonable" and not imprudent.

By using the CGA as a cost recovery mechanism, Northern will, in effect, receive virtually guaranteed recovery of the costs of the LNG project, most of which are fixed in nature. The CGA (and the FCA in electricity) mechanism, on the other hand, is primarily designed to protect the Company from losses due to regulatory lag which results from the incurrance of expenses which are highly variable and largely outside of the Company's control. The cost of the LNG Precedent Agreement, which is subject to a 20-year full embedded cost contract, does not represent a highly variable cost and is not likely to change once fixed due to factors beyond the Company's control.

On the other hand, there are benefits to including these costs in the CGA. First, it would recognize that, in a restructured gas market, the net costs associated with the tank might well resemble volatile gas costs more than "fixed" costs, and thus justify using the CGA mechanism for the LNG facility costs.

Conceptually, a LDC's costs fall into two broad categories, gas costs and non-gas costs. Non-gas costs are primarily the costs of building, maintaining, and operating the LDC's local distribution system. Gas costs are the costs of obtaining and transporting gas to the LDC's distribution system. Gas costs are incurred off-system. They include both demand and volumetric charges for gas supply, for pipeline transportation, for underground storage, for LNG storage, as well as some others. The demand charges amount to payments for fixed costs associated with facilities that the LDC does not own and that are not located on its system. In this case in particular, Northern will not own the LNG facility but will simply purchase its output service from Granite State at rates set by FERC. These LNG storage costs will not vary with usage; Northern must pay the full embedded costs of the facility over 20 years. But resale revenues will vary depending on how successful Northern is in selling its excess capacity.

The distinction between non-gas costs and gas costs corresponds to the unbundled model of the gas industry, where gas supply acquisition, transportation, and local distribution can be seen as three distinct transactions. Gas costs are for supply acquisition and pipeline transportation. Non-gas costs are for local distribution. At present the LDC arranges the purchase and pipeline transportation of the gas that it distributes to its customers. In theory, customers could make supply and transportation arrangements for themselves, or they could have third parties (marketers) do this for them. The LDC need not buy or sell any gas at all.

Northern's current rate structure reflects this conceptual distinction between gas and non-gas costs, although slightly imperfectly. Non-gas base rates recover non-gas costs, while gas costs are recovered through gas base rates and the CGA true-up mechanism, with the exception that some storage costs (underground) historically have been kept out of the CGA and recovered through non-gas base rates. The rationale for doing so had to do with the relatively constant nature of the storage costs at that time. Storage costs reflected both price (FERC rates), and quantity (Northern's selected storage demand level). Today, best practice gas portfolio strategy involves changing storage demand levels by making flexible tradeoffs between demand charges for various pipeline and storage facilities. By making timely purchases and sales of these kinds of capacity, all part of a complex optimization process, portfolio strategy is enhanced by the ability to vary quantities of many supply, storage, and pipeline options, in order to obtain a given quantity of gas reliably and at least total cost. Both underground and LNG storage are variables in this optimization process in precisely the same way that pipeline demand quantities and various gas supply options are. As noted above, it was this type of variability which the reconcilable recovery mechanisms of the CGA and FCA were designed to accommodate. Because storage costs are a variable in a dynamic optimization process it can be argued that they should not be treated as a relatively constant quantity.

A conceptually consistent treatment of gas costs would place all storage demand costs in the same category as other gas costs and would encourage varying them to the maximum extent required in order to minimize overall gas costs. Placing storage demand costs in non-gas rates will make it difficult to achieve a match between costs and recovery, if storage demand quantities vary much. It may also create undesirable incentives, by introducing differences in the nature of cost recovery for different variables that should all be managed at optimal levels. CGA recovery of storage demand costs provides a flexible and convenient mechanism for matching costs to revenues when rates and quantities vary, and will not introduce asymmetric incentives when trying to determine which resources to employ at what levels.[24] It should also be noted that compared to electricity, gas commodity prices are very weather sensitive and therefore highly volatile; storage helps hedge against such price volatility.

LNG storage facility costs will not vary, but resale amounts will. Employing the CGA true-up mechanisms will flow back resale revenues to ratepayers in a timely fashion. The alternative base rate recovery would require filing an amount in rates for recovery of the fixed LNG payments to Granite and also an estimate of Northern's likely resale of excess capacity possibly derived from historical trends. If Northern succeeds in getting greater revenues from resale, it would be entitled to retain that amount. Conversely, if it failed to achieve the estimated resale level, it would suffer those losses.

On balance, we agree with the OPA and the Company that the likelihood of resale of some portion of the LNG facility in the future would make it "impractical for the Commission to attempt to align rates with these changing portfolios in base rate proceedings." For this and other reasons, we believe that it

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[24] If storage demand costs are collected in non-gas base rates there will be an incentive to under use storage. If an optimal portfolio would involve increasing demand quantities by 30%, the Company will not do so because it will not recover the additional demand costs, at least not until its next rate case. Similarly, there is an incentive to reduce demand quantities and simply retain the over recovery.

is appropriate for the cost of the LNG facility to be passed on to ratepayers through Northern's cost of gas adjustment, and we will allow that treatment. Although we have some concerns that the timing of CGA proceedings may not be conducive to the type of in-depth analysis necessary to adequately monitor the Company's handling of its resource portfolio, in particular its management of resale opportunities, we do not believe the CGA treatment of these costs precludes the Commission from looking at Northern's management of this resource in a more comprehensive proceeding if one is warranted.

E. Precedent Agreement with PNGTS

We do not approve the Precedent Agreement between Northern and PNGTS. Northern's own optimization runs demonstrate that Northern's commitment to PNGTS represents significant excess over the optimal supply portfolio. The evidence regarding the possibility of resale, and Northern's own reluctance to accept any of the risk of such resale, indicate that Northern's assurances that it will be able to de-contract or resell this capacity at fully embedded cost may be overly optimistic. As noted above, we do not believe that there is anything in the Stipulation which provides meaningful protection to ratepayers from these concerns. Given Northern's insistence that any attempt by the Commission to condition approval of the PNGTS agreement on a specific rate making treatment which placed some of the risk for excess capacity on Northern's shareholders would be unacceptable to Northern and result in a withdrawal of the Company from the Precedent Agreement, we believe there is no reasonable option other than to reject the Precedent Agreement as adverse to the public interest and require Northern either to renegotiate its commitment to the PNGTS project to more closely reflect its optimal supply needs or to seek some alternative supply.

Although we are concerned that rejection of the Precedent Agreement with PNGTS may result in termination of a project which could provide benefits to ratepayers in Maine, we do not believe that this is a necessary or even likely result. The ownership of PNGTS comprises a variety of sophisticated market players who have already invested substantial time and energy in the development of the project. Though Northern might be expected to have some greater insight into the possible effect of Commission rejection of the Precedent Agreement on the likelihood of PNGTS's being completed, other experts in this case do not share the Company's pessimism about prospects for successful completion of the project absent a full 60,800 Dth/day commitment from

Northern. Mr. Rudkevich, for the OPA, stated that he still believes PNGTS will go forward even absent a commitment for a full 60,000 from Northern Utilities. Even Mr. Curley, who serves as the chairman of the management committee for PNGTS and is a director of Natural Gas Development Corporation, which is an investor in PNGTS, stated that his recommendation that PNGTS go forward would not change even if the Commission approved only an optimal amount of purchases by Northern. The likelihood that Mr. Curley's recommendation would prevail is suggested by Northern's exceptions to the Examiner's Report, which indicate a willingness to go forward of the Commission's approval of the Precedent Agreement is conditioned on reducing Northern's commitment.

Yet even if our failure to approve the Agreement resulted in the failure of the PNGTS project as currently planned, we do not believe that this fact alone would justify allowing Northern to enter into an agreement for such substantial excess capacity at this time. The best option for bridging the immediate short-term gap in supply caused by the expiration of the Portland Pipeline lease is the LNG facility at Wells. The value of this facility to ratepayers is largely independent of which of the competing pipelines eventually comes on-line to provide the necessary resource to allow Northern to optimize its mix.[25] We believe that it is too early in the process to despair of the possibility that the competitive market can provide additional pipeline resources that will more nearly match Northern's needs at reasonable cost. The participation of Maritimes in these proceedings has given the Commission valuable insight and information as to competing proposals for pipelines and other options for supply which may be available in the future. If a competitive market is to emerge in this state for natural gas, the Commission must demonstrate some confidence in the ability of that market to select the best option without the need for ratepayer commitment to substantial over-capacity in order to jump start a particular pipeline project. We

[25] We recognize that our rejection of the PNGTS Precedent Agreement may mean the GMLP transaction never occurs. As with all uncertainties, this risk must be balanced against the risk of shortages in the near term and the possible long-term detriments to ratepayers and the competitive market of significant excess pipeline supplies guaranteed by ratepayers. On balance we do not believe the possible benefits of the GMLP resale outweigh the risks of excess capacity created by the PNGTS agreement, nor are we persuaded that the possible risk to Northern of being unable to market excess LNG capacity justifies incurring the PNGTS excess.

agree with the Town of Wells, NO TANKS and Maritimes that the Commission should do everything in its power to see that the playing field is as level as possible for all potential competitors. If Northern's affiliates wish to compete for an opportunity to serve Northern's pipeline needs, they should be encouraged to bring to market a product which is more closely tailored to the needs of the customer they intend to serve. The evidence in this record indicates that there are other possible suppliers who may be willing and able to compete for this business on reasonable terms. Particularly in light of the possible unbundling of this industry in the near future, it is premature to discount the market's potential to bring an adequate supply of natural gas to this state.

In exceptions, Northern and PNGTS suggest that, if we do not approve the agreement as submitted, we should approve it subject to the condition that Northern's contractual responsibility be reduced to the levels indicated by its own needs (and not the full capacity of the pipeline). Such a reformation would certainly be an improvement; however, it may be that Northern will also want to re-examine the entire spectrum of its options (which might include, for example, an option for capacity on another pipeline if the PNGTS line is not built) before it seeks approval of a particular contract here. If a new filing is made,[26] we will act on the request quickly, using the record that we already have.

F. Further Proceedings

As noted above, paragraph 10 of the Settlement Agreement would have required Northern to make a good faith effort to file tariffs for Commission approval to make unbundled services such as transportation, load balancing and utility third party merchant services available to all customers no sooner than November, 1997 and no later than February, 1999.[27] OPA notes that a Chapter

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[26]We note that in its order granting preliminary approval, FERC indicated certain revisions would be needed before it awards final approval. If the PNGTS Precedent Agreement is submitted again for §707 approval, any changes that PNGTS is required to make in the FERC proceeding should be reflected in the revised filing here.

[27]Unbundling would allow customers to choose whether to buy gas from Northern or a third party supplier or marketer and transport it through Northern's distribution system.

120 revenue requirements filing, cost of service studies, a determination of the form of regulation going forward, and the filing of standards of conduct will be necessary before unbundled service tariffs may be implemented. The settlement agreement also includes the requirement that the Company file standards of conduct applicable to transactions with its affiliates or its conduct in relation to alternative suppliers by September 1, 1996 for review and approval.

Because there was an unresolved difference of opinion among the stipulating parties on when the Company should make its initial filing for unbundling, they asked that the Commission determine the date on which the Company must initiate the unbundling proceeding, given the range noted above and with the expectation that the date upon which unbundled service would be available would be no later than November, 1999. The OPA and Maritimes argued that Northern should file at the earliest possible date that the Commission finds convenient within the stipulated timeframe because they perceive the interests of ratepayers to be best served by expeditious movement toward this end.[28] The Company argued that it not be required to file an unbundling proposal until February 1999 and suggests that all parties continue to work together to establish a detailed schedule for filing no later than February 1999. Northern's position is based on its desire to have time and resources to put together a manageable plan, noting that unbundling will affect every segment of the Company. A later filing date would allow it to gather and incorporate additional information from its residential unbundling pilot program which is planned to begin in Massachusetts on November 1, 1996.

While we have not approved the stipulation, we nevertheless believe that the issue of future proceedings by Northern is an important one and we will address it. There are many questions about the best course of regulation for the gas industry in Maine which are timely for review and consideration. First, because the Commission has not reviewed Northern's revenue requirements for

[28] While all agree that the issue of unbundling should be investigated due to possible consumer benefits in the rapidly evolving gas industry, there is no clear consensus regarding whether complete unbundling should occur or what form of unbundling would best serve Northern's customers.

well over a decade,[29] such a review, at least for informational purposes, is overdue. Second, we have become increasingly aware that, like regulatory trends in the telephone and electric industries, the future regulation of the gas industry may be suited to some form of performance-based regulation. Like the electric industry, we are aware that consideration is being given nationally to the possibility of significant restructuring of the gas industry, such as residential unbundling, in the not too distant future. Consideration of these issues is, or is rapidly becoming, timely. As previously noted, Northern's parent corporation, Bay State Gas, has embarked upon a pilot program to evaluate residential unbundling and Northern itself states that it seeks to move to unbundle its services by the year 2000.[30]

Several steps that must be taken and careful consideration given before performance based regulation and unbundling, in whatever form it may take, should occur. We have set forth below a general timetable and sequence for the necessary proceedings; we leave it to the parties to work on a more definite schedule.

First, Northern must, within 120 days of the date of this Order, make an informal filing[31] of the financial information required under Chapter 120 (without testimony or proposed rate schedules) for preliminary review and analysis to determine whether a comprehensive review of the company's earnings is necessary either from the standpoint of our current regulatory system, or to serve

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[29]Northern's revenues were last adjusted in August 1984 in Docket No. 83-218.

[30] At the first technical conference in this proceeding, Northern presented its business plan to the Commission, indicating that it was committed to restructuring its corporate affairs according to company-wide business processes instead of geographic divisions, with the ultimate goal of unbundling its services into three distinct business segments: Local Transportation, Energy Products & Services, and Energy Ventures. It is also anticipated that only Local Transportation may remain a regulated public utility in the future.

[31]We use the term "informal" to distinguish this from the filing that a utility makes to initiate a rate case. The purpose of this filing, at least in the first instance, will be largely informational.

as a benchmark to inform alternative regulatory structures. The Company may consult with the Staff and with other interested parties to determine exactly what information will be filed, as well as the form it will take. We will then allow parties 30 days from the date of Northern's filing to recommend what further proceedings should occur. These steps will help to inform us, and the parties, on the need, and the appropriate process, for examining Northern's earnings and corporate structure and possibly developing alternative regulatory structures for the Company.

We have established an earlier time for the informational Chapter 120 filing than the range proposed by the parties because we expect, unlike an unbundling proposal, that Northern should be able to prepare such a filing relatively quickly and because it will provide a logical starting point in the process of determining the nature and course of future proceedings. It is possible that consideration of a performance-based regulation for Northern would occur first, followed by an unbundling proceeding. We do not have a sufficient record in this case upon which to make a decision about whether or not a rate review is warranted as an initial matter, or whether some other sequence of events will best serve the ultimate goals.

We will also require Northern to file an unbundling proposal (with proposed tariffs) to unbundle its services -- including transportation, load balancing, and utility third party merchant services -- by or before December 31, 1997. However, we will allow Northern to determine how to shape its proposal, such as whether all customers will be included initially or on a more gradual schedule. We agree with Northern that it will likely be beneficial to allow sufficient time to evaluate the Massachusetts pilot program.

We note that we have already indicated that we would conduct a broad inquiry into issues regarding gas regulation in Maine. That docket may be an appropriate place to review and determine the ultimate landscape for the evolution of some of the issues noted by the parties in this proceeding. Clearly, as suggested by the Public Advocate, the determination of what form of regulation or unbundling is desirable going forward is not a foregone conclusion, and in establishing the timeframe for these proceedings, we are endorsing no particular result at this time.

IX. CONCLUSION

For the reasons stated and on the basis of the evidence reviewed above, it is hereby

O R D E R E D, That

1. The Stipulation filed by the parties in this docket is not approved.

2. The revised Precedent Agreement between Granite State and Northern filed June 27, 1996 is not adverse to the public interest and is therefore approved pursuant to (35-A M.R.S.A. § 707).

3. The Precedent Agreement between Northern and Granite State is a prudent resource acquisition for the Company at current cost estimates ($50.4 million).

4. The Commission will continue to review Northern's management of its supply and resource portfolio including Northern's efforts to release, decontract or otherwise sell excess capacity from any source, and that nothing in this order shall relieve the Company of its obligation to continue to pursue beneficial opportunities to optimize its portfolio or restrict any party from requesting Commission review and disallowance of any excess expenses which may be incurred because of any demonstrated neglect or failure by Northern to use its best efforts to optimize.

5. The Commission's finding that Northern's Precedent Agreement with Granite State is prudent shall not restrict the Commission in entering any order which would otherwise be lawful regarding the timing, amount, method or desirability of stranded cost recovery for any resource acquisition made or contract entered into by the Company pursuant to this or any other order of the Commission.

6. The costs associated with Northern's commitment to the LNG project shall be phased into rates in a series of steps as proposed in paragraph 9 of the stipulation filed by the parties in this case.

7. A waiver of Chapter 43 of the Commission's rules is granted to permit recovery of the costs associated with the Precedent Agreement with Granite (and revenues from any sale or release of capacity) through the Cost of Gas Adjustment.

8. The Precedent Agreement between Northern and PNGTS is adverse to the public interest pursuant to 35-A M.R.S.A. § 707 and is not approved.

9. Within 120 days of the issuance of this Order the Company shall file the information required by Chapter 120 of the Commission's rules of practice and procedure, exclusive of testimony and proposed rate schedules, as well as standards of conduct governing dealings with its affiliates and alternative suppliers for review and approval.

Dated at Augusta, Maine, this 9th day of August, 1996.

BY ORDER OF THE COMMISSION

Christopher P. Simpson
Administrative Director

COMMISSIONERS VOTING FOR: Welch
Nugent
Hunt

APPENDIX A - PROCEDURAL HISTORY

A. Maine Proceedings

On December 11, 1995, Northern filed two Precedent Agreements for review and approval pursuant to 35-A M.R.S.A. §707(3), the statutory section governing affiliated transactions.[32] In a Precedent Agreement between Northern and Granite, Northern proposed to contract with Granite for a term of 20 years for 2 Bcf (or 2,000,000 Decatherm (Dth)) of liquefied natural gas (LNG) storage capacity and 54,600 Dth per day deliverability capacity, services Granite will provide from an LNG facility it will construct and own.[33] Over the term of the contract, Northern, Granite's only customer for service from this facility, would pay Granite the full embedded costs of the facility under FERC approved rates. The expected in-service date of the LNG facility is November 1, 1998. Granite and Northern are both wholly-owned subsidiaries of Bay State Gas Company (Bay State) and, therefore, are affiliates within the definition in §707(1)(A)(2). This agreement is dated September 14, 1995 and is signed by Thomas A. Sacco, Vice President of Northern and Dwight G. Curley, as President of Granite.

In the second Precedent Agreement, Northern proposes to contract with Portland Natural Gas Transmission System (PNGTS) for 1,100 million btu (MMBtu) of base load transportation service and 60,800 MMBtu per day of winter transportation services on a pipeline proposed to be constructed to carry gas from western Canada to Haverill, Massachusetts, entering the United States near North Troy, Vermont and continuing through Maine and New Hampshire to interconnect with the Tennessee Gas Pipeline Company's system. The pipeline has a projected in-service date of November 1, 1998. Northern indicates that it is an affiliate of PNGTS pursuant to §707(1)(A)(2) because Northern's "sister" company, Granite (through its wholly owned subsidiary, Natural Gas Development Corp. (NGDC)) owns more than 10% (29%) of the voting securities of PNGTS. This agreement is dated June 2, 1995 and is signed by Dwight G. Curley, as Vice

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[32] On December 14th, Northern made a corrected filing of the Precedent Agreement with PNGTS.

[33] On June 27, 1996, Northern filed a revised Precedent Agreement that increased the deliverability capacity allowed Northern to 134,000 Dth on the in-service date of PNGTS.

President of Northern, and James Leonard, for PNGTS.

Both the Wells LNG facility and the PNGTS pipeline projects are interstate natural gas pipeline facilities that must receive certificates of public convenience and necessity from FERC before they may be constructed.

A Notice of Proceedings, Procedures and Prehearing Conference was issued January 10, 1996, establishing an intervention deadline of January 30, 1996. The notice indicated that the Commission would not assign an advocacy staff to this case, but would rely instead on its advisory staff to ensure a full record. Timely petitions to intervene were received from the Public Advocate (OPA), the Town of Wells, NO TANKS, Inc., Distrigas of Massachusetts Corporation (DOMAC), Hannaford Bros. Co. (Hannaford), and the Industrial Energy Consumer Group (IECG).

At the request of the OPA, the proceedings were consolidated by Procedural Order dated January 30, 1996 based on the finding that there were likely to be common issues of fact and law surrounding Northern's supply planning and procurement needs and related actions that could be served more efficiently by consolidation.

A prehearing conference was held on February 2, 1996 at which the scope and schedule for the proceeding were discussed and all requests for intervention except Distrigas were allowed. An Order Denying Distrigas' Petition to Intervene as a matter of discretion was issued by the Commission on February 21, 1996.

On February 9, 1996, Northern filed its comments on the jurisdiction of the Maine Commission and its legal authority to condition its approval or reserve prudence determinations and ratemaking treatment of the projects. The Hearing Examiners issued a Procedural Order Regarding Scope of Proceeding on March 5, 1996. By letter filed March 20, 1996, Northern made an explicit request that the Commission make a prudence determination regarding the Precedent Agreements. As a consequence of this and other developments, the schedule for the proceeding was extended several times with Northern's concurrence.

On February 12, 1996, the OPA and the Town of Wells submitted a Motion to Require Northern Utilities to Retain Separate Counsel from that representing its affiliates in these transactions. The Examiners required Northern to provide an organizational chart showing the corporate officers and titles and trustees of Northern, Bay State, Granite and PNGTS. On March 26, 1996, the Examiners issued an order denying the request.

Two technical conferences were held for the purpose of conducting informal discovery, on March 20th and May 23. The conferences were recorded and transcribed by the Commission's reporters but were not automatically made part of the official record in this proceeding (as a hearing would be) unless parties requested the submission of parts of the transcript. A settlement conference, also attended by the Advisory Staff, was scheduled in conjunction with the second technical conference on May 23, 1996.

On March 1, 1996, the Company filed the direct testimony of Dwight G. Curley, in his capacity as Vice President of Northern Utilities, Inc.

On March 26, 1996, the Examiners issued a Protective Order to protect information regarding Northern's projected supply and transportation costs associated with resource alternatives from public disclosure. After considering comments and objection from Northern, by Order dated April 23, 1996, the Examiners denied Maritimes & Northeast Pipeline's request for Confidential Documents and Information made as a Freedom of Access request.

The Administrative Director issued suspension orders on February 9, 1996 and May 31, 1996 in accordance with 35-A M.R.S.A. §707(3)(A). On April 1, 1996, consistent with an agreement among the parties for schedule extension, Northern withdrew and refiled the two Precedent Agreements in order to allow further time to conduct this review. The refiling was treated as a procedural matter, and the original docket numbering and record were preserved. At the time of refiling Northern submitted a revised Precedent Agreement with PNGTS which included new provisions for "decontracting" pipeline reservation amounts that are in excess of Northern's projected optimal pipeline supply need.

On April 11, 1996, Maritimes & Northeast Pipeline L.L.C. (Maritimes or MN&E), a second pipeline proposed to be built through Maine with an estimated in-service date of November 1, 1998, filed a late-filed petition to intervene accompanied by the testimony of David E. Mackie, an independent consultant. Subsequently, on April 19th, the deadline for intervenor testimony, Maritimes filed the additional testimony of John W. Weber. Maritimes, a potential gas supply competitor for the New England region, had previously participated in this proceeding as an interested person, but later sought intervention after Northern requested a prudence review of the Precedent Agreements and its marketing practices on March 18. By an order dated April 23, 1996, Maritimes' intervention was granted as a matter of discretion by the Examiners under the condition that it take the case as it found it. Northern was also given an opportunity to file additional responsive testimony. A protective order was issued May 13, 1996 to allow Maritimes protection from public disclosure of information related to its marketing strategy.

On April 19th, the OPA filed the testimony of its consultants, Aleksander Rudkevich and Richard Hornby of the Tellus Institute. On May 7, 1996, Northern filed the responsive testimony of Dwight G. Curley, John J. Reed, of Reed Consulting Group, and Peter H. Kind, Independent Financial Advisor.

On April 30, 1996, PNGTS filed a late-filed petition to intervene arguing that since Maritimes had been allowed to intervene, intervention by PNGTS would be necessary to place the issues in the proper context. PNGTS was allowed intervention as a matter of discretion on May 3, 1996 subject to the condition that it take the case as it found it and that it would be consolidated with Northern for purposes of cross examination at hearings.

On May 3, 1996, Distrigas filed its second Motion to Intervene arguing that since the denial of its initial petition to intervene, the case had expanded and other interested persons had been allowed intervention in order to provide information on the developing gas supply markets in the Northeast. Distrigas' motion was considered a request for reconsideration of the Commission's February 21 Order denying its intervention and was denied by operation of law after 20 days pursuant to Chapter 110, section 1004.

Depositions of Louis J. DiStefano of PanEnergy and Tina V. Schiaraffa of Tenneco Energy were taken on May 24, 1996 and were entered into the record in this proceeding with corrections. Northern filed Revised Projected Costs of the Wells LNG facility on May 28, 1996.

A settlement agreement (stipulation) joined by the OPA, Northern, and Maritimes was filed on May 29, 1996. NO TANKS and the Town of Wells opposed the stipulation. A hearing on the stipulation was held on May 29, 1996 and a final hearing on all issues in this case was held on June 18, 1996. At the hearing, NO TANKS cross-examined the witnesses that had prefiled testimony in this proceeding, with the exception of Richard Hornby.

A copy of the definitive interconnection agreement between Granite and Maritimes referred to in the stipulation was filed on June 6, 1996.

The stipulation contains an agreement to extend this proceeding for final order until August 9, 1996. By letter dated June 12, 1996, Northern indicated it would withdraw and refile the Precedent Agreements on or before July 29, 1996, to allow further time for consideration of these proceedings.

On June 25, 1996, counsel for the Town of Wells informed the Commission that FERC had dismissed Granite's filing for certification of the LNG facility without prejudice stating that the purpose of the facility had changed from use as a base load facility to a peaking facility, and asking that FERC's order be admitted into the record in this proceeding. By letter dated June 25, 1996, Northern informed the Commission that FERC had dismissed Granite's filing without prejudice. Northern indicated that Granite State intended to reapply within the week. Northern requested that no change to the schedule for determination of this case be made.

In addition, Northern indicated that it was in the process of executing a revised Precedent Agreement with Granite that reflected the anticipated use of the LNG facility in conjunction with PNGTS. Specifically, the revised precedent agreement allows Northern the entire vaporization capacity of the facility (134,000 Dth per day, or double the deliverability capacity in the original Precedent Agreement) once PNGTS is in service. On June 27, 1996, Northern filed a revised Precedent Agreement with Granite and indicated that the rate structure had also been modified from capacity and deliverability charges to a single deliverability charge.

On June 28, 1996, Northern filed a proposal to modify the Cost of Gas (CGA) mechanism to incorporate the 90%/10% customer/company sharing of revenues derived from off-system sales, capacity releases and on-system interruptible transportation, pursuant to the proposed stipulation.

The OPA's Response to the Hearing Examiner's First Oral Data Request, regarding Northern's historical performance on capacity release, was filed on July 1, 1996.

The Town of Wells and NO TANKS requested an extension of the schedule to allow further investigation of the new agreements. The Hearing Examiners' denied this request by procedural order dated June 27, 1996. Briefs were submitted by Northern, OPA, Maritimes, NO TANKS and the Town of Wells (consolidated) on July 2.

On July 5, 1996, Northern filed 1) the Agreement for LNG Storage Capacity and Deliverability between Northern Utilities and Gaz Metropolitain and Company, Limited Partnership (GMLP) for the release of 1 Bcf of storage capacity in Granite's LNG facility once PNGTS came in-service, 2) an Option Agreement between Granite State and GMLP to allow GMLP to acquire up to 50% equity interest in the proposed Wells LNG facility, and 3) a Liquefaction Option Agreement between Granite and GMLP providing for future construction of liquefaction capability at the facility at the request of GMLP.

Supplemental briefs were allowed on July 10th to address issues arising as a result of the June 21 FERC dismissal, the June 27th revised Precedent Agreement and the final capacity release agreements filed July 5th, all of which occurred after the close of hearings in this case. Supplemental briefs were submitted by Northern, OPA, Maritimes, NO TANKS and the Town of Wells (consolidated).

Bench Data Request #5, regarding the revised Precedent Agreement and Granite's revised LNG project filing at FERC, was issued on July 11, 1996. All prefiled testimony was admitted into the record. Responses to Bench Data Request #5 were filed with the Commission on July 16, 1996.

An Examiners' Report was issued July 18th and exceptions were filed by NO TANKS and the Town of Wells, OPA, Northern, PNGTS and Maritimes, on July 25th. On August 2, 1996, NO TANKS and the Town of Wells filed a Joint Motion requesting that the Commission take Official Notice, pursuant to Section 927 of Chapter 110 of the Commission's Rules of Practice and Procedure, of two FERC rulings dated July 31, 1996, regarding pending pipeline certification requests by PNGTS and Maritimes. The FERC orders grant preliminary approval on non-environmental issues for both the PNGTS and Maritimes pipeline projects.[34]

The Commission deliberated on August 5, 1996, and in the course of deliberations took official notice of the FERC orders.

B. Related Proceedings Before the Federal Energy Regulatory Commission

1. The Granite State LNG Facility

Granite originally filed an Application for a Certificate of Public Convenience and Necessity and for an Order Authorizing the Abandonment of Facilities and Services for its LNG Plant Project in Wells, Maine, pursuant to Sections 7(b) and 7© of the Natural Gas Act, on November 3, 1994. It requested approval of this project in order to provide replacement service on November 1, 1997, the beginning of the first heating season after the termination of the Portland Pipe Line lease. The lease was scheduled to terminate on March 31, 1997. Granite sought preliminary determination on the non-environmental aspects of the application by March 1, 1995 and final approval by June 30, 1995. Granite indicated that the loss of the 31,000 MMBtu per day of natural gas supply provided from Canada would substantially impact Northern, which had no other acceptable or certain supply alternatives. Granite indicated that a southern prebuild of PNGTS would be more costly at $70.3 million than the LNG facility at $44 million.[35] Granite proposed that Northern pay the full costs of the facility over a 20-year contract term under a FERC approved tariff and would provide Northern LNG storage, vaporization and transportation of gas. Northern would be entitled to a maximum take-away capacity of 54,600 MMBtu per day, sufficient to meet its design day requirements in 1997-1998. The 2 Bcf size was designed to be more feasible to refill by trucking for base load use on a year-round basis.

In February, 1996, Granite succeeded in negotiating a lease extension of the Portland Pipe Line until April 30, 1998, forestalling a supply need

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[34] On August 5th, Northern filed a response to arguments made in the joint motion, but did not object to having the Commission take official notice of the FERC orders. The response was received after deliberations.

[35] The current project estimate is $50.4 million.

until November 1, 1998.

FERC issued its draft environmental impact statement (DEIS) on the project in February 1996.

On June 21, 1996, finding the purpose of the facility had changed, the Director of the Office of Pipeline Regulation dismissed Granite's filing "without prejudice to the refiling of your proposal to change from baseload to peakshaving service."

On July 1, 1996, Granite filed its revised application for certification of the LNG facility at FERC, proposing that the facility would provide peak shaving service in conjunction with PNGTS. For any period of time during the winter season prior to PNGTS's in service date, the facility would function as a base load supply for Northern. The revised filing included a revised rate structure and tariffs.

2. Maritimes and Northeast Pipeline, L.L.C.

On February 8, 1996, Maritimes filed its Application for Certificate of Public Convenience and Necessity for a two phase pipeline project proposed to bring natural gas from the Sable Islands to connect with the Tennessee Gas Pipeline Company facilities in Dracut, Massachusetts. Maritimes proposed to build the southern leg of this project (Phase I), from the Tennessee interconnection to Wells, Maine first, approximately 64.1 miles of 24-inch pipeline, with an estimated in-service date of November 1, 1997. On July 31, 1996 the FERC issued its preliminary determination approving the project on the basis of non-environmental issues. A review of environmental issues is ongoing. Maritimes seeks a final order by April 1997.

3. Portland Natural Gas Transmission System

On March 14, 1996, PNGTS filed its Application for a Certificate of Public Convenience and Necessity to authorize its construction of a 242 mile, 20-inch natural gas pipeline from the Canadian border in Vermont through Maine to Haverill, Massachusetts. PNGTS requested a preliminary determination by August 1, 1996 and a final certificate by July 1, 1997, to permit an in-service date of November 1, 1998. On July 31, 1996, the FERC issued its preliminary determination approving the project on the basis of non-environmental issues. A review of environmental issues is ongoing. PNGTS seeks a final order by July, 1997.