DOCKET NO. 27

AN APPLICATION OF THE UNITED ILLUMINATING COMPANY FOR A CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY AND PUBLIC NEED FOR THE MODIFICATION OF BRIDGEPORT HARBOR UNIT NO. 3 TO CAPABILITY TO BURN EITHER LOW-SULFUR COAL OR OIL.	: : :	CONNECTICUT SITING COUNCIL January 11, 1983

FINDINGS OF FACT

1. The United Illuminating Company (UI) in accordance with provisions of sections 16-50k and 16-501 of the General Statutes of Connecticut, Revision of 1958, revised to 1981, as amended, applied to the Connecticut Siting Council on June 18, 1982, for a Certificate of Environmental Compatibility and Public Need for the modification of Bridgeport Harbor Station Unit No. 3 (BH 3) to provide capability to burn either low-sulfur coal or oil. (Record)
2. The fee prescribed in section 16-50v-1(b) of the Regulations of Connecticut State Agencies accompanied the application. (Record)
3. The application was accompanied by proof of service as required by section 16-501(b) of the General Statutes. (Record)
4. Affidavits of newspaper notice as required by Statute and section 16-501-1 of the Regulations were also filed with the application. (Record)
5. Pursuant to section 16-50m of the General Statutes, the Connecticut Siting Council, after giving due notice thereof, held a public hearing at the Bridgeport City Hall, Common Council Room, 45 Lyon Terrace, Bridgeport, Connecticut, on August 17, 1982, including an evening session for the convenience of the public, and on September 17, 1982. (Record)
6. The parties to the proceeding are the applicant and those persons and organizations whose names are listed in the Decision and Order

which accompanies these findings. (Record)

7. The Council on Environmental Quality and the Department of Economic Development filed written comments with the Council pursuant to section 16-50j(f) of the General Statutes of the State of Connecticut. (Record)

8. On August 17, 1982, members of the Council made an inspection of the facility. (Record)

9. The applicant proposes to convert its existing oil fired BH 3 on the west shore of Bridgeport Harbor to a dual fuel (coal/oil) capability. (UI 1)

10. The conversion of this unit to coal would provide cost savings to customers, reduce oil dependency, diversify UI's fuel mix, provide protection against delays in the completion of the nuclear units in which UI is a participant, and provide back-up generation during out-of-service maintenance periods of other generators. (UI 1, p. A6; Tr. 8/17/82, p. 15)

11. Continuous oil price increases create substantial adverse economic conditions for customers. (UI 1, p. A3; Tr. 8/17/82, p. 11)

12. UI operates nine oil fired units which represent 96% of its total generating capability. (UI 1, p. A2; Tr. 8/17/82, p. 11)

13. During 1981, UI burned approximately 7.4 million barrels of oil in its generating units to supply approximately 92% of its customers' electric energy requirements. (UI 1, p. A3; Tr. 8/17/82, p. 12)

14. BH 3 represents 33% of UI's fossil-fired capacity and 31% of its total generating capacity. (UI 1, p. B1)

15. BH 3 is UI's second largest generating unit and is the largest unit that UI could convert to dual firing capability. (UI 1, p. B1)

16. Conversion of BH 3 to dual fuel capability would reduce UI's oil dependency by approximately two million barrels annually, assuming annual production of approximately 1,457 gigawatt hours. (UI 1, p. A6, UI 2, Q. 29, 44; Tr. 8/17/82, p. 15)

17. The proposed conversion, in concert with the UI nuclear construction program, would reduce UI's oil dependency from over 90% to about 20% by 1990. Nuclear generation is expected to displace 3.75 million barrels of oil per year for UI. (Tr. 8/17/82, p. 20; UI 1, p. A9)

18. The gross cumulative savings from the proposal are projected to total $307.4 million by 1993, based upon UI projections of future oil and coal prices. (UI 2, Q. 34; Tr. 9/17/82, pp. 7,8)

19. The cumulative gross savings for the period 1984 to 1993 are estimated at $136.8 million using a 10 year amortization period plan and based on the 1982 planning forecast, filed with the Council, of 1.4% growth in sales annually between 1981-1991. (Tr. 8/17/82, p. 18; Tr. 9/17/82, p. 3; UI 1, p. 9; UI 2, Q. 34,36)

20. UI presently relies heavily on imported fuel oil for energy production, therefore the company's costs and rates are substantially affected by oil prices. (UI 1, p. A3, A6; Tr. 8/17/82, pp. 2, 13)

21. Total costs of energy in the New England area may continue to make the area uncompetitive for energy intensive industry. In the energy mix, electricity pricing is expected to become more competitive with oil and gas in the future. (UI 1, p. C-9)

22. The area surrounding BH 3 includes industrial, commercial, institutional, recreational, and residential land uses, with the institutional and recreational uses and most of the residential uses

separated from the station by either the harbor or a two-block wide area of industrial and commercial uses. (UI 1, p. H1)

23. The areas within a two mile radius to the west, north, and east of BH 3 are densily populated residential areas with eight or more dwelling units per acre. (UI 1, p. I-2)

24. Elevated Conrail train tracks run immediately adjacent to the Bridgeport Harbor Station on the northeast. (UI 1, pp. H1-2)

25. The main portion of the University of Bridgeport campus is approximately one-half mile southwest of BH 3. (UI 1, p. H 2)

26. The majority of Seaside Park (a shoreline park) is approximately one-half mile from BH 3. (UI 1, p. H2)

27. Development on the east shoreline of Bridgeport Harbor, located one-third of a mile from the station, is predominantly heavy industry. (UI 1, p. H2)

28. At present, BH 3 burns residual oil containing not more than 1% sulfur in conformance with Connecticut State Regulations. (UI 1, p. B3)

29. Bridgeport Harbor Station Units number 1, 2, and 3 are capable of burning coal. (UI 1, p. A8; Tr. 8/17/82, p. 17)

30. Bridgeport Harbor Units No. 1 and 2 were initially considered as candidates for conversion. However, the unavailability of the required coal, likely need for flue-gas desulfurization, and costs in excess of those projected for BH 3 removed them from further consideration. (UI 2, Q. 40; Tr. 8/17/82, p. 17)

31. BH 3, while originally designed and constructed to burn both coal and oil, has burned only residual oil since its start-up in August, 1968. (UI 1, p. B1)

32. After BH 3 started operating in 1968, no design changes in the plant were made. Boiler tube modifications have been made to improve the reliability of the boiler's operation but did not necessarily improve the efficiency of oil burning. (Tr. 8/17/82, p. 10)

33. State and Federal environmental agencies have determined that BH 3 was capable of burning coal prior to December 22, 1976, and that the proposed conversion does not constitute a modification under the federal New Source Performance Standards which regulate air emissions. (UI 2, Q. 31)

34. Almost all of the facilities required for coal handling and burning now exist at BH 3. (UI 1, p. A8)

35. The plant was planned to burn coal commercially, but the burning of coal is now precluded by deterioration of the equipment, lack of maintenance and operation, and environmental regulations enacted since 1968. (Tr. 8/17/82, p. 11)

36. The existing facility, burning oil, attains compliance with air pollution regulations concerning oxides of sulfur by controlling the amount of sulfur in the fuel. (UI 1, p. B8)

37. The existing facility, burning oil, attains compliance with air pollution regulations concerning oxides of nitrogen by the use of calibrated combustion controls on the boiler. (UI 1, pp. B8-9)

38. The existing facility, burning oil, attains compliance with air pollution regulations concerning particulate emissions by the use of an electrostatic precipitator. (UI 1, p. B8)

39. Particulate emissions testing is performed on a schedule determined by the Connecticut Department of Environmental Protection

(DEP) which is approximately once every five years for BH 3. (Tr. 9/17/82, pp. 22-23)

40. Existing stack monitoring instruments, precipitator monitoring, and alarm instrumentation provide the operator with continuous status reports on the precipitator system. Operating instructions for coal would specify immediate lowering of firing rate of the boiler in case of precipitator loss. (UI 1, p. B21)

41. BH 3 has an existing capability of 410 megawatts when firing oil, which capability would be retained after conversion. (UI 1, pp. A3, B18)

42. The Unit is proposed to operate primarily as a base load generator, burning coal at approximately 250 MW. (UI 1, p. B18)

43. Conditions requiring the full 410 MW (oil) capacity of the unit would be unexpected or occur in emergency situations. (UI 2, Q. 25)

44. UI estimates that the change from coal to oil would take a maximum of four hours with the return to coal taking the same time. (UI 2, Q. 26)

45. Assuming a conventional life of 40 years, the existing facility, burning oil, is expected to have 25 years of remaining life. The proposed conversion is not expected to shorten or extend that period. (Tr. 8/17/82, p. 186; UI 1, p. B20)

46. UI proposes to burn a low-sulfur, low-ash coal often referred to as medium or marginal metallurgical quality coal, which typically has a sulfur content of 0.6-0.7% and an ash content of 6-8%. (UI 1, p. A7; Tr. 8/17/82, p. 16)

47. The coal UI proposes to burn is generally found in the southern

part of West Virginia and the eastern part of Kentucky. (UI 2, p. A7; Tr. 8/17/82, p. 16)

48. UI would enter into contracts to purchase coal that would ensure that the emissions rate of SO_2 would not exceed the current state limit of 1.1 lbs/10^6 Btu. (UI 1, p. H11)

49. UI's coal supply contract would specifically limit coal quality to that which would fully comply with Connecticut's regulations with respect to sulfur content. (UI 1, p. A7; Tr. 8/17/82, p. 16)

50. Five coal suppliers would be capable of meeting UI's projected requirements for periods varying from ten to twenty years, and that measured recoverable reserves of coal meeting the 1.1 pounds of sulfur per million Btu requirement have forty-five years of production capacity. (UI 1, p. A7; UI 2, Q. 5; Tr. 8/17/82, p. 16)

51. In addition to the heat content and sulfur testing procedures at the mine described in appendix B of Exhibit J in the application, ash content would also be determined at that time by the American Society for Testing and Materials (ASTM) Standard Testing Method #D-3174. (Tr. 8/17/82, pp. 168-169; UI 4)

52. In addition to the heat content and sulfur testing procedures, the Proposed Coal Quality Assurance Sampling Program procedure presented as appendix B of Exhibit J in the application, which would have entailed retesting upon receipt of the coal in Bridgeport, is no longer planned by UI. (UI 2, Q. 2; Tr. 8/17/82, p. 166)

53. Coal for use in BH 3 would be delivered in 8,000 to 10,000 ton barges pushed individually by tugboats. (UI 2, p. H30)

54. The amount of coal burned is a function of the capacity at which the unit is operated. (Tr. 9/17/82, p. 21)

55. At 250 MW, BH 3 would burn approximately 500,000 tons of coal or 50 to 65 barge deliveries per year. (UI 1, pp. H30, A7; Tr. 8/17/82 p. 16)

56. The existing coal transportation system would be adequate to meet UI's requirements. (UI 1, p. A7; Tr. 8/17/82, p. 16)

57. The projected frequency of barge delivery is one every six to seven days with some seasonal variations to one every four to five days at peak demand periods. (UI 1, pp. H30-31)

58. The coal unloading facilities that were constructed as part of the original project in 1968 are state-of-the-art. (UI 1, p. B4-5)

59. All coal handling equipment has been designed and constructed according to the National Fire Association Codes for explosion proof design. (UI 1, pp. B20-21)

60. The coal dock has been examined by divers and found to be in serviceable condition; some repairs would be required, the exact nature of which has not been determined. (UI 1, p. H10)

61. Some upgrading of the coal dock tender system might be required. (UI 1, p. B4)

62. A device might be added to the barge unloading facility to restrict the lateral movement of the coal barge during the unloading process. (UI 1, pp. H10, B5)

63. The primary conveyor system was installed at the time of construction and is, for the most part, enclosed. (UI 1, pp. B5,H15)

64. The results of UI's fugitive dust dispersion modeling showed that increases in ambient concentrations greater than or equal to 5

micrograms per cubic meter (deemed significant for State and Federal air quality regulations) would occur almost entirely on UI property or over water and decrease rapidly with distance. (UI 1, p. H17)

65. Fugitive emissions from wind action and coal handling would be minimized by dust suppression sprays composed of city water and small amounts of a wetting agent or surfactant mixed at concentrations on the order of 500 ppm. (UI 1, p. H4)

66. Dust suppression sprays are located at critical transfer points throughout the coal unloading system. (UI 1, p. B6; Tr. 8/17/82, pp. 18, 156)

67. Coal would be sprayed with dust suppressant at the barge unloader, the hopper at the lower end of the conveyor, the crusher house, and as it falls to the active coal pile. (Tr. 8/17/82, p. 156; UI 1, pp. H4, H5, B13)

68. Each of the several alternative methods of minimizing wind blown dust from the inactive coal pile involves the use of a cover/crusting agent. (UI 2, Q. 8)

69. A surface bonding agent would reduce the infiltration of precipitation into the coal pile. (UI 1, p. H18; UI 2, Q. 4)

70. Normally, coal pile coverings are put down to reduce wind erosion, not necessarily to encourage runoff. (Tr. 8/17/82, p. 174)

71. UI investigations to date have not shown contamination by straw and bitumen reserve pile covers to be a problem in reclaiming the coal. (Tr. 8/17/82, pp. 174-175)

72. The specified coal may not require processing in the existing preparation crushers. (UI 1, p. B5)

73. In addition to dust suppression sprays, the existing dust collection and removal system would be refurbished and put back into service. (UI 1, p. B7)

74. Two different types of pneumatic vacuum collection systems would be installed to control fugitive emissions from the movement of coal. (UI 1, p. H15; Tr. 8/17/82, p. 18)

75. A baghouse dust collection system would be installed at the crusher and transfer house. The existing dust control system above the coal storage silos would be upgraded. (UI 1, p. H15)

76. The stockout boom would have a telescoping cylindrical chute enclosing the falling coal to reduce the exposure of the falling coal to the wind, thus minimizing dust. (UI 1, pp. H4-5)

77. UI's plans call for extending the telescoping chute on the stockout boom to within several feet of the ground. (Tr. 8/17/82, pp. 175-176)

78. In addition to the residual effects of the dust suppression sprays in reducing fugitive emissions, spray nozzles located on the stockout boom would be capable of treating much of the active coal pile. (UI 1, p. H5)

79. The existing coal sampling device, which allows for sampling of the coal as it is being unloaded from the barge, would be overhauled. (UI 1, p. B5)

80. Coal would normally be deposited directly on top of the reclaim hopper from the stock out conveyor; however, mobile yard equipment would move coal from the active pile to the reclaim hopper if no coal is being delivered at a time that the boiler demands fuel. (UI 1, p. B7)

81. The new coal storage piles would be re-established in the general area where they were located until the mid 1970's. (UI 1, p. B12)

82. The reserve coal would be stored on the ground near the coal handling system in a gently sloped, wedge-shaped pile approximately thirty feet high, covering approximately three to four acres. (UI 1, pp. B12-13, H29)

83. The water table under the proposed coal storage pile is five to ten feet below existing grade, and the first twenty feet of soils under the proposed coal piles are classified from silty to gravelly sands. (UI 2, Q. 3)

84. The effects of tides on the level of the water table below the coal storage area have not been determined. (Tr. 8/17/82, p. 171)

85. To prevent spontaneous combustion, the inactive coal pile would be compacted to a density of about 70 pounds per cubic foot. This is a recognized practice in the industry. (Tr. 8/17/82, p. 230; UI 2, Q. 6)

86. Because all of the harbor's recreational boat marinas are located on the opposite side of Bridgeport Harbor from the station, the mooring and docking of coal barges would not be expected to interfere with recreational boating. (UI 1, p. H32)

87. Stocking the reserve and active coal piles would require 10-20 barge deliveries in the six months prior to operation. (UI 1, p. H31)

88. All systems, whether additions or modifications, would be designed, constructed, and operated in accordance with the applicable regulations under the Occupational Safety and Health Act and

any other applicable, local, state, and federal statutes. (UI 1, p. B20)

89. A coal pile runoff system would be designed and installed prior to the unloading of the first barge, to collect rainwater which runs off the coal pile and pump it to the existing wastewater treatment system. (UI 1, pp. B13; pp. H9,18; Tr. 8/17/82, p. 18)

90. The actual percentage of precipitation that would be expected to be diverted into the coal-pile runoff channel has not been determined. (UI 2, Q. 4)

91. The coal-pile runoff channel would be compacted, reducing wind erosion of its surface. (UI 1, p. H4)

92. An extensive wastewater treatment facility has been constructed at the Bridgeport Harbor Station. (UI 1, p. B9)

93. UI would undertake necessary modifications and additions to the existing wastewater treatment system to ensure that the quality of the treated wastewater discharge from BH 3 would remain well within the effluent guidelines established by the existing U.S. Environmental Protection Agency (USEPA) and DEP discharge permit limits. (UI 1, p. H17; Tr. 8/17/82, pp. 19-20)

94. The DEP wastewater treatment discharge permit upgrading which would be required has not been applied for but would be when the character of the waste waters has been determined. (Tr. 8/17/82, p. 188)

95. The wastewater system contains sufficient holding capacity for retention of any effluent that would be unacceptable for discharge in case of a breakdown of the treatment system. (UI 1, p. 21)

96. The retention capacity of the wastewater treatment facility is

well within the USEPA requirement of sufficient capacity to collect all runoff from a one-day-in-ten-year storm, which is 4.8 inches in 24 hours. (Tr. 8/17/82, p. 186; UI 1, p. H19; UI 9)

97. A new support facilities building is included in the proposal which would provide for required increases in operating personnel and staff; mechanical, electrical and instrumentation repair; fuel testing facilities; and space for storage and handling of spare parts and tools that are necessary to support the additional equipment required for coal burning. (UI 1, pp. B17-18)

98. The new support facilities building would abut the south wall of the existing station and measure approximately 122 ft by 100 ft by 52 ft high. (UI 1, p. H29)

99. A new support facilities building would also address the issue of the control room layout and prevent overcrowding. (UI 1, p. B18)

100. The existing control systems would be replaced with state-of-the art equipment to increase efficiency, versatility, and reliability. (UI 1, p. B10; UI 3)

101. Some pile-driving would be required for the foundation of the new support facilities building. (UI 1, p. H6)

102. The new support facilities building would probably eliminate the need for several temporary structures presently located near the area of the proposed building. (UI 1, p. H29)

103. Some changes are necessary in the boiler and auxiliary equipment in order to burn coal. These include replacement of superheater and reheater tubing, new soot blowers, and replacement of ignitors and pulverizer parts. (UI 1, p. B10; UI 3)

104. Proposed changes in boiler design involve a change in the pattern

of heat transfer surface in the boiler. (Tr. 8/17/82, p. 11)

105. The original bottom ash removal system would be replaced with a new design which consumes and discharges significantly less water. (UI 1, p. B11)

106. UI is considering upgrading the wet sluice bottom-ash removal system with a closed loop recirculating system. (UI 1, p. B11)

107. As part of the bottom-ash system, UI assumes it will be utilizing some of the existing Connecticut Resource Recovery Authority (CRRA) equipment on a lease basis to close the loop to recirculate sluice water. The equipment would be replaced or returned on demand to CRRA. (UI 1, p. B11; Tr. 8/17/82, pp. 151-152, 9/17/82, p. 65)

108. Use of the CRRA ash equipment on site would not preclude the future use of Units No. 1 and 2 for burning refuse-derived fuel. (Tr. 9/17/82, p. 65)

109. The water used for bottom ash removal would be collected, treated, and for the most part recycled with all discharges directed to the wastewater facility for treatment prior to final discharge. (UI 1, p. B11)

110. After the existing precipitator received significant structural, mechanical, and electrical modifications, the manufacturer of the unit, Research Cottrell, would guarantee specific particulate removal efficiencies for the type of coals now planned for use. (UI 1, p. B14-15)

111. The existing oil fly ash removal systems would be replaced with new systems for removing both coal fly ash and oil fly ash. (UI 1, p. B15)

112. Both types of fly ash would be moved by pneumatic vacuum systems. (UI 1, p. H16)

113. Mixing oil and coal fly ashes would make the coal fly ash unmarketable. (UI 1, pp. B16,17)

114. Each of the ashes (coal fly ash, coal energizer ash, coal bottom ash, and oil ash) would be collected separately to minimize impurities and enhance marketability. (UI 1, p. H23)

115. The existing fly ash silo bottom would be modified to provide a fully enclosed area for the unloading of coal fly ash. (UI 1, p. B16)

116. Fly ash would be transported by trucks loaded in a shelter equipped with two types of loading equipment that minimize dust generation. (UI 1, p. H16)

117. Under UI assumptions (250 MW capacity; coal with 8% ash and 13,000 Btu/lb; 60% capacity factor), ash production would be 40,000 tons annually, which equals 36,000 cubic yards or 22.3 acre-feet. This would require eight twenty cubic yard truck trips per day. (UI 1, pp. H20-21; Tr. 8/17/82, p. 19)

118. There is a direct relationship between ash generation and capacity of BH 3 on coal. A 20% increase in capacity (250 to 300 MW for example) would be expected to increase ash generation 20% (36,000 to 43,200 yd^3/year). (UI 1, pp. H20-21; UI 2, Q. 13)

119. UI estimates that at least 50% of the total ash generated annually by the proposed conversion could be used for productive purposes. (UI 1, p. H22)

120. Approximately 10-15 percent of the coal ash produced annually in the U.S. is utilized for partial replacement of cement in concrete

production, road base materials, and lightweight concrete. The market for fly and bottom ash as commercial products in New England has not been established. (CLF 1, p. 63; Tr. 8/17/82, p. 19; Tr. 9/17/82, pp. 143-148)

121. The New England Electric System projected 1982 fly ash sales of 116,000 tons, plus 75,000 tons to a private contractor, to be used as interim or final landfill cover. (Tr. 9/17/82, p. 26)

122. The primary use of that fly ash which is marketed nationwide is in the production of concrete; however, if the ash from BH 3 were to be stored, it is unlikely it could be used for this purpose. (Tr. 9/17/82, pp. 30,143)

123. The marketability of fly ash cannot be accurately determined until coal has been burned for several months to determine the ash's characteristics. (UI 1, p. H23)

124. Eight of eleven commercial firms contacted have expressed an interest in UI's coal ash as a marketable product. However, UI must demonstrate its ability to produce ash consistent with certain quality requirements by actually burning coal in BH 3 before any of these firms will contractually commit to purchase UI's ash. (Tr. 9/17/82, pp. 142-143)

125. In Connecticut fly ash is classified for disposal purposes under the category of mixed solid waste, the same as municipal solid waste. (Tr. 8/17/82, p. 24)

126. The state generates approximately 7,000 tons of solid waste per day, totaling 2,250,000 tons per year. This amount would cover twenty acres, ten feet deep. (Tr. 8/17/82, p. 55)

127. Municipal landfills have run out or are running out of space, and

towns are unable to find suitable or socially acceptable disposal sites. Towns will need to rely more heavily on regional landfills which already accept 40% of the state's solid waste. (Tr. 8/17/82, pp. 56,64)

128. The eight major landfills in the state, which represent approximately 40% of the state's existing garbage disposal capacity, will be full by 1986. (Tr. 8/17/82, pp. 57, 63; CLF 4)

129. At 250 megawatts and 60% capacity factor, the total ash generated from the proposed conversion would add less than 1% to the state's annual volume of solid wastes now being landfilled. (Tr. 9/17/82, p. 149)

130. The Norwalk Harbor Station Study Task Force found no existing permanent fly ash disposal sites with sufficient capacity within a 37 mile radius of the Norwalk Harbor power station in their April, 1980, report. (Tr. 8/17/82, p. 32; CLF 1, p. 59)

131. The DEP ash disposal guidelines recommend that fly ash should go into its own cell or individual area within an existing permitted landfill, or that it should go into a landfill which is permitted for fly ash only. (Tr. 8/17/82, p. 35)

132. If DEP approved fly ash as an interim landfill cover, the utilization of fly ash could approach 100%. (UI 1, pp. H22-23)

133. The permits required from DEP for a new ash disposal facility are a solid waste permit and a discharge to groundwater permit. (Tr. 8/17/82, p. 40)

134. The DEP guidelines for fly ash disposal (1976) prefer the use of fly ash as a portion of final landfill cover and not for intermediate cover material. (Tr. 8/17/82, p. 36)

135. It might be possible to place anywhere from one to three or four feet of fly ash over a landfill followed by a foot of soil to form a final landfill cap. (Tr. 8/17/82, p. 44)

136. UI would send specific plans for the placement of fly ash in existing landfills to DEP for review and approval. (Tr. 9/17/82, p. 146)

137. Because a dedicated, long-term ash landfill is not available, UI is analyzing several temporary ash storage locations at its generating stations at New Haven Harbor (13.8 acres), Steel Point Station (4.2 acres), and Bridgeport Harbor Station itself. (Tr. 8/17/82, p. 19; UI 1, pp. H24-25)

138. The possible on-site locations for ash storage total approximately 8.5 acres and are north and east of the existing oil storage tanks. (UI 2, Q. 12)

139. UI would consider ash to be in short term storage indefinitely, as long as the ash is intended for later use or removal. (Tr. 8/17/82, p. 181)

140. On-site ash storage would require the same DEP permits as would a new off-site disposal area. (Tr. 8/17/82, p. 181)

141. UI has conducted no studies to determine the environmental impacts of ash disposal at any of its candidate sites for temporary storage. (Tr. 9/17/82, p. 28)

142. On-site ash deposition would require the approval of the local coastal zone management agency which, is the Bridgeport Planning and Zoning Commission. (Tr. 9/17/82, p. 53)

143. UI has not determined the underlying soils or the depth to water table for the approximately 8.5 acres identified as possible on-

site storage areas. (Tr. 8/17/82, p. 182; UI 2, Q. 12)

144. The Bridgeport Harbor on-site ash disposal area proposal could accomodate approximately four years of ash generation at the proposed capacity and utilization levels. (Tr. 9/17/82, pp. 37,149)

145. Whenever ash were to be moved, it would be wetted down before being loaded onto trucks, which should allow the use of a bucket loader and simple dumping techniques without additional dust suppression. (Tr. 8/17/82, pp. 179-180)

146. UI has not surveyed landfill operations in neighboring states nor has it had any discussions with out-of-state landfill operators regarding disposal of ash. UI would consider but has not investigated the use of abandoned mines. (Tr. 8/17/82, p. 144; UI 2, Q. 10)

147. Since neither the amount of ash requiring storage nor the location of storage or disposal sites have been determined, the land use impacts of this aspect of the proposed conversion cannot be quantified. (UI, p. H28)

148. UI is not presently pursuing ocean dumping as an option for ash disposal. (Tr. 8/17/82, p. 140; UI 2, Q. 11)

149. Based on maximum heat input and an 80% capacity factor, Northeast Utilities predicted the following maximum annual quantities (lb/yr) of eight principal trace elements if its Norwalk Harbor coal conversion were to take place as planned:

	Bottom Ash	Fly Ash	Suspended Particulates
Cadmium	19	225	69
Chromium	5140	9430	287
Copper	1300	7160	218
Fluorine	1660	31970	972
Lead	230	7600	231
Manganese	2440	19150	582
Mercury	1.2	557	16.9
Nickel	1580	24460	744

(CLF 1, p. 57)

150. Fly ash contains large quantities of silica, alumina, and ferric oxide. (UI 1, pp. J 62, 68)

151. Some of the trace elements found in coal and concentrated in the bottom and fly ashes are:

Aluminum	Calcium	Gallium	Mercury*
Antimony*	Cesium	Hafnium	Molybdenum
Arsenic*	Chromium	Iron	Nickel
Barium	Cobalt	Lanthanum	Potassium
Beryllium*	Copper	Lead*	Rubidium
Cadmium*	Europium	Magnesium	Samarium
		Manganese	
Scandium	Tantalum		
Selenium*	Thorium		
Silicon	Tin		
Sodium	Titanium		
Strontium	Vanadium		
Sulfur	Zinc*		

(*listed by American Lung Association as potentially hazardous)
(UI 1, p. J63; ALA 1, p. 11, CLF 2, p. 3-8)

152. Bridgeport Harbor Station is a class C or industrial use area for noise regulation purposes. (UI 1, p. H25)

153. Ambient noise levels are high in the area of the Bridgeport Harbor. (UI 1, p. H7)

154. Most noise associated with the conversion of BH 3 would result from outside construction activity and coal handling as the active and reserve coal piles were created. (UI 1, p. H6)

155. The mobile coal pile equipment, barge unloader, and truck traffic associated with ash removal would be the major new sources of noise associated with the operation after conversion. (UI 1, pp. H25-27)

156. Noise from the barge unloader and the mobile yard equipment may be noticeable in South Bridgeport. (UI 1, p. H26)

157. The estimated noise level at the nearest residential receptor resulting from mobile coal handling equipment would be 55-58 dBA, which is below the 66 dBA daytime allowable level in such a receptor area. (UI 8)

158. UI intends to limit the operation of the barge unloader and mobile equipment on the coal piles to those hours when ambient noise levels are high (7:00 a.m. to 10:00 p.m.) except under unusual circumstances. (UI 1, pp. H26-27)

159. Construction activity associated with the conversion would increase the normal traffic volume on the roads in the area of the station. (UI 1, p. H7)

160. It is estimated that about 200 construction workers would be employed at the peak of construction activity on the BH 3 conversion project. (UI 1, p. H7)

161. Visibility of the construction activity from off-site would be limited since the nearest residence from which construction might

be visible is about 1200 feet from the site of the proposed new support facilities building. (UI 1, p. H8)

162. Conversion of BH 3 would have no impacts on land use in the area immediately surrounding the station. (UI 1, p. H28)

163. The proposal's short-term air quality impacts would involve the dust typically generated during construction and fugitive emissions released during the creation of the active and reserve coal piles. (UI 1, p. H3)

164. Most of the area to be excavated would remain exposed for short periods while foundation forms were constructed and concrete poured. (UI 1, pp. H3-4)

165. UI would use standard erosion control methods, such as settling basins, temporary dikes, and filter fences, if needed, to ensure minimal water quality impact from construction activity. (Tr. 8/17/82, p. 19; UI 1, p. H9)

166. UI would review the adequacy of the site's existing road and bridge structure to handle traffic increases. (UI 1, p. B18)

167. UI would pave the on-site roads used by ash trucks to minimize dust. (UI 1, p. H16)

168. UI would provide additional landscaping, where appropriate. (UI 1, p. B18)

169. Road paving and plantings which are currently planned could improve the overall appearance of the station. (UI 1, pp. H29-30)

170. The projected sulfur dioxide (SO_2) emissions rate would not exceed the allowable limits established in the Connecticut State Implementation Plan (SIP). (UI 1, p. H11)

171. The SO_2 emissions rate would remain the same as during the burning

of 1% sulfur residual oil (1.1 lb $SO_2/10^6$ Btu). (UI, p. H11; Tr. 8/17/82, p. 134)

172. UI expects no significant change in current ambient levels of SO_2 resulting from proposed conversion because the emission rate would remain at or below the current level. However, no modeling has been performed with regard to this effect. (UI 2, Q. 16)

173. The ambient air pollution levels provided by UI are based on 1979 information and current levels are not available. (Tr. 8/17/82, p. 118; UI 2, Q. 16)

174. The increase in November, 1981, of the state's sulfur-in-fuel limit from 0.5% to 1% is not reflected in the latest ambient air quality information provided. (Tr. 8/17/82; UI 2, Q. 16)

175. The 1% sulfur-in-fuel limit is now on appeal in the Second Circuit Court of Appeals. If Connecticut's standard reverts to the 0.5% limit, UI would abandon the plan for coal conversion. (Tr. 8/17/82, pp. 140-141)

176. Changes in the SO_2 emissions rate resulting from the proposed conversion would be minimal because of the characteristics of the coal to be burned. (UI 1, p. H11)

177. With BH 3 generating at 250 MW with a 66.3% capacity factor, the annual SO_2 emissions would decrease from the 1981 emissions level. (UI 2, Q. 17)

178. The Federal Air Quality Control Region in which the modification is proposed is classed as attainment for ambient levels of SO_2 and NO_2. (UI 2, Q. 16)

179. BH 3 is located in Air Quality Control Region 43 which is currently classified as non-attainment for the secondary ambient

air quality standard for total suspended particulates (TSP). (UI 1, p. H12)

180. UI plans to upgrade the electrostatic precipitator and operate initially at approximately 250 MW when burning coal to ensure compliance with the SIP TSP standard. (UI 1, p. H12)

181. At the reduced load of 250 MW, the efficiency of particulate collection would increase, since the flue gases and entrained particles will pass through the precipitator at a slower rate. (UI 1, p. H14)

182. The rate of particulate emission depends in part on the electrical resistivity of the ash in the coal. (Tr. 9/17/82, p. 18)

183. In order to achieve lower emission rates for total suspended particulates, UI plans to install a flue gas conditioning system utilizing SO_3 to increase the precipitator efficiency. Flue gas conditioning has been determined by UI's engineering to be a requirement to attain maximum efficiency from the precipitator. (UI 2, Q. 46; Tr. 9/17/82, pp. 18-19)

184. The injection of SO_3 by the flue gas conditioning system is not expected to have any significant adverse effect on the final emission levels of sulfur compounds. (UI 2, Q. 46; Tr. 8/17/82, p. 98)

185. According to state regulation 19-508-3(c)(7)(i), the amount of ambient impact that will be considered significant or will exacerbate a violation of the 24 hour average state or national ambient air quality standard for TSP is 5 micrograms per cubic meter. This applies to new or modified stationary sources, of which the BH 3 proposal is neither under regulatory definition. (UI 2, Q. 21,31)

186. UI has conducted air quality modeling, using the Point Multiple version A for Connecticut (PTMTPA Conn) dispersion model (developed by the USEPA and used by DEP for its emission modeling) which predicts increases in 24-hour ambient concentration of TSP of less than 5 micrograms per cubic meter as a result of the proposed conversion. (Tr. 8/17/82, p. 201; UI 1, p. H12, UI 2, Q. 21)

187. UI has in hand a guaranteed proposal of 99% overall efficiency of precipitator particulate removal. (Tr. 8/17/82, pp. 137,139)

188. No increases are expected in ambient levels of TSP due to the conversion of BH 3 at any capacity factor. (UI 2, Q. 16)

189. Based on actual stack tests conducted March 10, 1982, the current rate of TSP emission from BH 3 is 0.06 pounds per 10^6 Btu. (UI 2, Q. 18)

190. Increases in TSP emissions rates above the present level of 0.06 lb/10^6 Btu on oil, may occur at any generating capacity above approximately 290 MW on coal. (UI 2, Q. 16,46; UI 13)

191. Improving the efficency of particulate removal beyond that of the existing systems could be accomplished by a new electrostatic precipitator (ESP), and a fabric filter, or the addition of a balanced draft. The cost would be in excess of $37 million (1981$). (Tr. 9/17/82, pp. 19-21)

192. A particulate size distribution analysis for the TSP emissions after coal conversion was not done; As much as 30% of total particulate emissions could be 2.5 microns in diameter or less. (Tr. 8/17/82, p. 136; Tr. 9/17/82 p. 23; Lung Association 1, p. 9)

193. The ESP is very effective in removing large particles but may not

be very efficient in eliminating the fine particles. (Tr. 9/17/82, p. 115)

194. Even if the total amount of particulate emission by weight from BH 3 on coal is the same as on oil, the health impacts may be worse because of the shift to the finer particle sizes. (Tr. 9/17/82, pp. 127-128)

195. Fine particulates, microscopic or invisible solids or liquids with particles in the range of one-half to two microns, may penetrate the lung and be retained. (Tr. 9/17/82, pp. 105-107, 116)

196. Because of the nature of the combustion process with coal, there is likely to be a much higher production of respirable chemicals than with the oil-fired system. (Tr. 9/17/82, pp. 113, 129)

197. There is an inverse relationship between the size of the particles and the quantity of toxic chemicals they will carry into the lungs with them. Therefore, health impacts might increase even if TSP emissions do not. (Tr. 9/17/82, pp. 114, 128)

198. The individuals most susceptible to lung damage are people sixty-five years of age or older whose normal lung defenses against these materials have diminished, people with established lung disease, and small children. (Tr. 9/17/82, p. 112)

199. There have been no final determinations regarding adverse health impacts of fine particulates. (Tr. 9/19/82, pp. 23-24)

200. The Bridgeport Harbor Unit No. 3 boiler is a Combustion Engineering tangentially fired boiler, generally considered to be the best design for minimizing NO_x formation. (UI 1, p. H14)

201. The SIP restricts the rate of NO_x emission for coal units to 0.90 $lbs/10^6$ Btu, and the NO_x emissions rate would be 0.53 $lbs/10^6$ Btu

from BH3 operating at 250 MW. At 300 MW the NO_x emission rate would be approximately 0.56 lbs/10^6 Btu. The present emissions rate of NO_x from oil generation is 0.23 lbs/10^6 Btu. (UI 1, p. H14; UI 2, Q. 18)

202. The NO_x emission rate resulting from this conversion would be less than the maximum allowed for a new source today, and the plant emissions would be small compared to the total NO_x emissions in the area. (Tr. 8/17/82, p. 143)

203. Annual emissions of NO_x from BH 3 will increase approximately 122% if coal conversion is accomplished and the unit operates at 300 MW. (UI 2, Q. 17)

204. Based on actual stack tests on oil and manufacturer's projections at 300 MW on coal, NO_x emissions per kWh from BH 3 would increase 143% on coal. (UI 2, Q. 18)

205. The combustion of coal as proposed in the application would increase BH 3's nitrogen oxide emissions, which would directly affect the levels of ozone in this state. (Tr. 9/17/82, p. 68)

206. Connecticut now fails to attain the state and federal standards for ozone. (Tr. 8/17/82, p. 143, UI 2, Q. 16)

207. During the summer months in Connecticut, the 0.12 ppm EPA standard for ozone concentrations might be violated one out of every three or four days. (Tr. 9/17/82, p. 69)

208. There are two major precursors of ozone: hydrocarbons and nitrogen dioxide. (Tr. 9/17/82, pp. 70-71)

209. UI did not examine the effect of nitrogen oxides on ozone formation. (Tr. 8/17/82, p. 143)

210. Connecticut's high humidity and high background hydrocarbon levels

enhance ozone formation relative to other parts of the country. (Tr. 9/17/82, pp. 73,76)

211. There could be unquantified increases in ozone in the effluent plume produced from the stack, regional increases in ozone, and faster generation of acid rain components from the proposed conversion 20-30 kilometers or more downwind. (Tr. 9/17/82, pp. 98,99)

212. UI has performed no modeling with regard to the effect of the proposed conversion on ambient levels of NO_x. (UI 2, Q. 16; Tr. 8/17/82, p. 143)

213. UI did not look at secondary pollutants from transformation of nitrogen dioxide and sulfur dioxide to nitrogen and sulfates. (Tr. 8/17/82, p. 138)

214. UI did not consider the formation of acid rain from increases in sulfur dioxide emissions. (Tr. 8/17/82, p. 146)

215. UI did not examine the effect of nitrogen oxide on acid rain formation. (Tr. 8/17/82, p. 144)

216. UI did not examine interstate transportation of pollution. (Tr. 8/17/82, p. 139)

217. Operating at 250 MW on coal would produce less hydrocarbon emission than is produced by operating at 410 MW on oil. (UI 1, p. H14)

218. On coal at 250 MW generation, with a capacity factor of 66.3%, annual carbon monoxide emissions would increase to approximately 133 times the level currently produced on oil. (UI 2, Q. 17)

219. UI's emergency plan, on file with the DEP, calls for a reduc-

tion in generation in affected areas in case of air pollution emergency. (UI 1, pp. B21-22)

220. If violations of air quality standards occurred at 250 MW, UI would switch the unit back to oil. (Tr. 8/17/82, p. 142)

221. UI plans to start initial operation with coal at 250 MW and then as stack tests are taken, increase capacity in twenty-five megawatt increments until an emission or opacity limit is reached. Specific monitoring method and criteria were not provided. (Tr. 8/17/82, pp. 133-134, 205; Tr. 9/17/82, p. 52)

222. TSP emissions or opacity would likely be the capacity limiting factor. (Tr. 8/17/82, p. 206)

223. In a worst case situation the unit would meet the TSP emission standard of 0.14 lb/10^6 Btu at a capacity of 360 MW. (Tr. 9/17/82, p. 162; UI 13)

224. UI's modeling indicates that at any capacity from 250 to 410 megawatts, Unit No. 3 could emit up to 0.14 lb TSP/10^6 Btu and not raise ambient levels by 5 micrograms per cubic meter. (Tr. 8/17/82, p. 204)

225. The opacity of the Unit No. 3 plume would be increased from its current five to seven percent to between ten and fifteen percent. (Tr. 9/17/82, p. 161; UI 2, Q. 20)

226. UI has a corporate commitment to avoid visible emissions from BH 3 if converted. (Tr. 9/17/82, p. 163)

227. The relationship between TSP emissions and percent opacity is very nearly a linear relationship, and the upper limit for opacity (20%) is within the range of .06 to .08 lb TSP/10^6 Btu. (UI 14)

228. The estimates of the percent opacity of the stack plume at various TSP emission rates provided by UI range from 2.5 to 3.3 times the value filed by Northeast Utilities and accepted by the USEPA for the Mt. Tom coal unit in Massachusetts, which could achieve opacity complience at approximately 0.2 lb TSP/10^6 Btu. (UI 14; CSC Docket F-82, NU 7 Administratively noticed)

229. If capacity were to increase over 250 MW, the coal requirements, barge traffic, yard activity, ash generated, and annual emissions would increase while effective coal reserves and years of short term ash storage availability on-site would decrease. (Tr. 8/17/82, p. 207)

230. BH 3 is operated primarily as a base load unit and is dispatched by the New England Power Exchange (NEPEX) to meet the load requirements of the New England Power Pool (NEPOOL). (UI 1, pp. B1-2)

231. The four-year average availability for the period 1978-1981 for BH 3 has been 85.2%. (UI 1, p. B3)

232. Based on a net capability of 410 MW, BH 3 operated at a 43.04% capacity factor during 1981.
(UI 1, p. B2)

233. UI expects forced outage rate would increase on coal, especially during the early years. (UI 1, p. B19)

234. UI studies project forced outages of 10%, 6% and 4% during the first three years of coal firing. (UI 1, p. B20)

235. By the third year of operations, UI predicts the forced outage rate on coal of the converted BH 3 would level off at 4%. (UI 2, Q. 27)

236. An additional week (2%) would be added to each year's pre-planned preventive maintenance schedule (planned outage rate) on coal. (UI 1, p. B20)

237. Based on actual planned outages on oil for 1978 through 1980 (3.75%) plus 2% (1 week increase planned for coal requirements over oil) plus the projected levelized forced outage rate of 4% on coal, the availability of Unit No. 3 on coal could eventually reach 90% (UI 1, p. B2,20; UI 2, Q. 27)

238. Based on the economy of coal generation, BH 3 would be dispatched whenever available by NEPEX to meet NEPOOL requirements. (Tr. 8/17/82, pp. 193,197; F-82, Tr. p. 309)

239. UI's projected 1984 to 1993 capacity factors of 53.4 to 66.4 percent are based on own-load projections while the unit is and would be dispatched at a higher level by NEPEX based on NEPOOL requirements. (UI 2, Q. 29; F-82, Tr. pp. 308-309; Tr. 8/17/82, p. 132)

240. UI expects BH 3 to be out of service for twelve weeks for conversion as proposed. (Tr. 8/17/82, p. 212)

241. BH 3 on coal is not expected to produce electricity at the annual rate it has produced on oil. (Tr. 8/17/82, p. 196)

242. BH 3 will be used less after 1985 when the Seabrook Unit is expected to come on line. (Tr. 8/17/82, pp. 213,214; UI 2, Q. 29)

243. UI proposes to convert BH 3 from oil-firing to dual-firing because available coal will allow satisfaction of environmental and boiler requirements within reasonable time and capital costs. (Tr. 8/17/82, p. 17)

244. During the twelve week outage required for the conversion construction phase, generation will be replaced as necessary by

NEPOOL. (Tr. p. 8/17/82, pp. 212,213)

245. UI would return to oil fired operation of BH 3 if external factors prohibited coal firing. (Tr. 8/17/82, p. 218)

246. All economic analyses of the proposed conversion assumed operation at the 250 MW level, at which point coal generation becomes economical and meets UI's criteria. Analysis of operations at the 400 MW operational level was not undertaken since it was assumed this level was unobtainable. A reasonable economic operational level would be approximately 300 MW. (Tr. 9/17/82, pp. 50,59,141)

247. UI's estimate for the capital cost of converting BH 3 to dual firing capability is approximately $35 million (1982$). New equipment would account for $10,990,000 of this. (Tr. 8/17/82, p. 18, UI 1, p. E1; UI 10)

248. The projected cost-of-work on the boiler is $4,453,000, of which $2,060,000 is for new equipment. (Tr. 8/17/82, p. 148; UI 3)

249. The bottom ash hopper system may have to be completely changed at additional costs of $1.8 million, which is included in the total. (Tr. 8/17/82, p. 150, UI 3)

250. Electrical system improvement costs are estimated at $3,342,000 which are attributable to renovation or replacement of motors and controls, 62 of which are used in the outdoor coal handling system. (Tr. 8/17/82, p. 152; UI 1, p. E1)

251. Support facility costs are placed at $2,474,000 which includes new construction of additional maintenance shops, tool storage, and control room expansion. Of this total $1.4 million is for new equipment. (Tr. 8/17/82, p. 155; UI 1, p. E1; UI 3)

252. The fire protection systems would cost $1,150,000, of which

$750,000 will be required for new equipment. Included in these costs are the addition of new piping and sprinklers around the handling belts, and a new master fire pump to increase pressure to all points where fire protection is required. (Tr. 8/17/82, pp. 158,159, UI 1, p. E1; UI 3)

253. Equipment costs can be divided and allocated between replacement components, new components, and installation of already owned components never installed. These could be designated either maintenance or new equipment costs, depending on use and age. (Tr. 8/17/82, pp. 162-164)

254. The $341,000 for site improvement includes paving of some on-site roads. (Tr. 8/17/82, p. 220)

255. The cost of using either a vegetative or chemical cover over the reserve coal pile would be $10,000-$15,000. (Tr. 9/17/82, p. 137)

256. Engineering costs, including consultant fees, would be approximately $1,720,000. (Tr. 8/17/82, p. 159)

257. BH 3 incremental operation and maintenance costs (1982$) could be $3,884,000 annually. (DPUC Docket 82-04-13, administratively noticed)

258. The proposed conversion technology is the most cost effective available in the foreseeable future. (Tr. 8/17/82, p. 209)

259. Bridgeport Harbor Units 1 and 2 could have been reconverted to coal firing in 1977 for a combined cost of $45 million. This cost would have increased 50 percent or more by 1982. (UI Exhibit 2, Q. 40; Tr. 8/17/82, p. 218)

260. The financing mechanism for providing funds for this project has been tentatively approved by the DPUC, although no definitive plan

has been worked out to date. (Tr. 8/17/82, p. 215)

261. A financing plan with a ten year amortization period formed the basis of the economic analysis of the project. A five-year amortization period financing plan as presented to the DPUC is an alternative option intended to speed up the process of cost recovery. (Tr. 8/17/82, p. 214)

262. The total cost of the project with a ten-year amortization period is estimated at $84.53 million. The cost of the project with a five-year amortization period, as proposed to the DPUC, would be $61.4 million, a difference of some $23 million. (Tr. 8/17/82, p. 217; UI 2, Q. 32,36; DPUC Docket 82-04-13, administratively noticed)

263. The reduced cash requirements attributable to possible delays in nuclear projects could ease UI's financing responsibilities but would not necessarily provide the money to effect the coal conversion. (Tr. 8/17/82, p. 214)

264. The proposed financing method for the conversion project would not require issuance of debt or equity securities, nor would it reduce UI's credit quality or interest coverage ratios of present indentures. One possible method would be a facilities lease agreement, whereby another company would assume financing obligations. (DPUC Docket, 82-04-13, administratively noticed; Tr. 8/17/82, p. 219)

265. The financial feasibility of the project is not dependent upon load growth. (Tr. 9/17/82, p. 3)

266. UI's average annual rate of load growth in their 1982 forecast is 1.4 percent for the first ten years of the forecast period and 1.5 percent over the twenty year period; UI's actual load growth has

been negative the last two years. (Tr. 9/17/82, pp. 3,4; UI 1, p. C6-106)

267. UI's 1981 sales are lower than 1973 sales, due to high electricity prices. (Tr. 9/17/82, p. 4; UI 1, pp. 6-37)

268. Total sales growth for the 1981-2001 period could be at or below -0.2 percent annually. (UI 1, p. C4; Tr. 9/17/82, p. 5)

269. All of the savings accruing from the conversion would flow to the customers. (Tr. 9/17/82, p. 42)

270. Increased construction costs for nuclear units in which UI participates would not be met by savings due to BH 3 coal conversion. (Tr. 9/17/82, p. 58)

271. The net annual savings from burning coal in BH 3 would fall between $8 and $25 million per year during the ten-year period following commencement of coal burning in 1984. (Tr. 8/17/82, pp. 18,20; UI 1, p. 9)

272. Savings projected under UI's low load growth forecast could be $55 million over the first ten years of operation, which is a 60% reduction from those projected at the planning forecast growth rate. (Tr. 9/17/82, p. 6)

273. Operating at a capacity higher than 250 MW would increase the potential savings by approximately $12.3 million for every ten MW of additional capacity. (Tr. 9/17/82, p. 139)

274. Net annual savings were calculated by deducting from estimated gross savings the incremental costs of operation and maintenance expenses, property taxes, coal pile inventory worth, and amortization of capital costs. (UI 2, Q. 34)

275. If a five year amortization period is used, UI estimates the cumu-

lative net savings for the period 1984-1993 at $159.9 million as compared to the $136.6 million for a ten year amortization period. The difference of $23.2 million would also be passed on to the customers. (UI 2, Q. 36)

276. Based upon current estimates of coal and oil prices, the gross annual savings for the period 1994-2001 would range from $48.0 million in 1994 to $103.2 million in 2001 and would total $593.5 million for the eight year period. (UI 2, Q. 35)

277. A net cumulative savings of $455 million could be achieved by coal generation from 1994 to 2001. (UI 2, Q. 35)

278. A decline of 32 percent in net annual savings from 1985 to 1988 would be followed by a 63 percent jump in savings in 1989. The decline and rise would be due to the nuclear plants coming on line followed by a maturation of their forced outage rates. (Tr. 8/19/82, p. 219; UI 2, Q. 34)

279. Based on the assumptions that average residential customer use will be 500 kwh/month, that sales of five billion kWh per year will produce $135 million savings, and that coal price per Btu will be approximately 60% of oil prices, the savings per kWh would be approximately 2.7 mills/kWh, yielding an average annual savings per residential customer of $16.20. (Tr. 9/17/82, pp. 6,7,55)

280. All oil price forecasts by UI are lower than the latest Data Resources Incorporated (DRI) oil price forecasts at the time of the hearing, resulting in lower savings figures than would be produced using DRI estimates. (Tr. 9/17/82, p. 55)

281. A reduction in the price of electricity would benefit the company as well as customers. (Tr. p. 42)

282. In 1981, nearly 60% of UI's annual revenue, or $259 million, was used to pay fuel costs. (Tr. 8/17/82, p. 13)

283. The price of oil escalated from $3.99 per barrel in 1972 to $40.26 in early 1981 and as of August, 1982, was priced at $27.51 per barrel. (Tr. 8/17/82, p. 12)

284. In 1972, UI customers paid $0.007 per kilowatt hour for oil fired generation, while in 1981 the cost was $0.057 per kilowatt hour. (Tr. 8/17/82, p. 13)

285. Oil prices are expected to increase from $32.40 per barrel in 1984 to $162.28 per barrel in 2001. (UI Exhibit 2, Q. 35)

286. The 1983 delivered price of coal is estimated at $73.00/ton which equals $2.81/10^6 Btu. This is 60% of the delivered cost of oil. (Tr. 8/17/82, p. 17)

287. The 1983 price of coal is expected to increase 1.6% from 1983 to 1984 and then by 2.3% annually until 1993. This increase is judgmentally derived from various industry forecasts of price increase and inflation rates. (Tr. 9/17/82, p. 8)

288. Coal prices are estimated at $80.04/ton in 1984 and $422.29/ton in the year 2001. (UI 2, Q. 35)

289. Based on UI's projected annual fuel costs, one year of operation of BH 3 in 1984 producing approximately 1,329,150 MWh of electricity would cost approximately $28 million more with oil than coal. (UI 2, Q. 38)

290. In 1984, #6 oil at $25.45/bbl could generate electricity at the same cost as 0.7% sulfur coal. (UI 2, Q. 44)

291. Delivered oil price at the time this application was filed was $28.04/bbl. At 14,800 Btu/gallon this is 451 cents/10^6 Btu. (UI

2, Q. 43(b))

292. Delivery of coal from West Virginia to Bridgeport by rail and barge would cost \$24.50 to \$26.50/ton. Using only rail delivery systems, the cost would range from \$26.50 to \$29.50/ton. This total delivered coal price with all rail shipping would equal 263-283 cents/10^6 Btu. (UI 2, Q. 43(b))

293. Coal delivered by rail only is projected to cost 169-189 cents/10^6 Btu less than oil. (UI 2, Q. 43(b))

294. UI owns 17.5% of the 2300 megawatt Seabrook Units and 3.68% of Millstone III's 1150 megawatt unit. In 1984, UI expects Seabrook I to displace 1.75 million barrels of oil annually from UI's projected usage. When the other nuclear units come on line in 1986, an additional 2 million barrels will be displaced. (Tr. 8/17/82, p. 14)

295. Of the \$900 million additional cost for the construction of Millstone III recently announced by Northeast Utilities, UI's approximate cost is \$34 million. (Tr. 9/17/82, p. 57)

296. The cost of adding a new and larger precipitator to the existing precipitator in order to improve its efficiency is estimated at \$37 million in 1981 \$, which includes the cost of a fabric filter but does not include up to \$37 million in costs for additional changes than would be required. (Tr. 9/17/82, p. 20; DPUC Docket 82-04-13, administratively noticed)

297. Addition of a scrubber would require additions of equipment on new foundations in the yard, supported by new pilings. These design changes would increase project costs. (Tr. 9/17/82, p. 20)

298. UI developed a capital cost range of \$100 to \$150 million for the

addition of exhaust gas scrubbers to the proposed system. (Tr. 8/17/82, p. 209)

299. UI estimates annual maintenance costs for a lime scrubber of approximately $2.9 million. (UI 10)

300. The estimated installed cost of a clay-lined coal pile underdrain system would be $665,000, plus or minus 25%. . (UI 5)

301. If, by governmental agency order, scrubber and fabric filter units were required, at an approximately cost of $190 million, UI would not proceed with the conversion. (Tr. 9/17/82, p. 56)

302. UI did not estimate the total cost of the project under any amortization financing plan with the scrubbers added because the company does not consider such a plan economically feasible. (Tr. 9/17/82, p. 56-57)

303. The conversion proposal does not include a balanced draft boiler conversion which is recommended by the boiler manufacturer. This equipment could be added in the future at an estimated cost of $8-10 million. The decision will depend on maintenance and reliability considerations. (Tr. 9/17/82, p. 47)

304. Coal gassification conversion of BH 3 would be more expensive than the present proposal. (UI 2, Q. 41)

305. Modification of a UI facility to permit refuse-derived fuel burning could not be completed by 1984 and would exceed the costs estimated for the proposed BH 3 conversion. (UI 2, Q. 41; Tr. 9/17/82, p. 13)

306. The use of the Wellman-Nord Process to recover flue gases for conversion into acids would be more costly than a standard limestone FGD system. (Tr. 8/17/82, p. 211)

307. UI estimates that if purchase of Hydro-Quebec power were commenced in 1986, the price of coal generation for BH 3 would still be 80 percent of the delivered Hydro-Quebec price based on an average 12-month fossil fuel cost in New England. (Tr. 8/17/82, p. 210)

308. In a study of fly ash transportation in 1978, C.E. McGuire determined that wastes could be transported up to 37 miles from a mixed solid waste source at a cost ranging from $7 to $10 per ton. (Tr. 8/17/82, p. 46)

309. Including transportation to a disposal site, the McGuire study assumed a tipping fee ceiling for fly ash of approximately $15 to $20 per ton. (Tr. 8/17/82, p. 46, 73)

310. The proposal includes an ash disposal allowance of $45-$50 per ton, which UI considers to be a high estimate. The analysis is based on a 50 mile shipping limit and includes trucking costs and tipping fees. (Tr. 8/17/82, p. 234; Tr. 9/17/82, p. 60)

311. The capital cost estimates for ash management do not include the costs of hardware needed to carry out the plan. (Tr. 8/17/82, p. 234; UI 1, p. E1)

312. To the extent possible, UI would use local contractors for the on-site construction work. (Tr. 8/17/82, p. 220)

313. No proposals had been requested from construction companies at the time of the hearing. (Tr. 8/17/82 p. 223)

314. UI states that each month's delay in securing contracts would increase fuel and other costs and thus reduce the savings that would be produced by the coal conversion. No specific figures were calculated by UI. (Tr. 8/17/82, p. 221)

315. The state DPUC determined that the proposed project would be in

the public interest, provided that environmental, health, and safety issues were resolved. (DPUC Docket 82-04-13, administratively noticed)

316. Changes in the federal tax laws are not expected to affect significantly the leasing provisions of the proposal. (Tr. 8/17/82, p. 235)

317. Future generator conversions in the region would require more ash disposal space and total emissions would be greater regionally. Those emissions may not affect the same receptor. (Tr. 8/17/82, p. 236)

318. Higher federal oil tariffs on oil would increase the price differential and savings attributable to the proposed conversion. (Tr. 8/17/82, p. 235)