Title: WELLBORE LEAK DETECTION SYSTEMS AND METHODS OF USING THE SAME

Abstract: A leak detection system for a wellbore. The leak detection system includes: (1) at least one sensor configured to be positioned outside of a casing of the wellbore; (2) an interrogation system for sending signals to and receiving signals from, the at least one sensor; and (3) an optical lead cable disposed between the interrogation system and the at least one sensor. A method of detecting a fluid leak in a wellbore is also disclosed.
WELLBORE LEAK DETECTION SYSTEMS
AND METHODS OF USING THE SAME

RELATED APPLICATION

This application claims the benefit of priority to U.S. Provisional Patent Application Serial Number 61/525,269, filed on August 19, 2011, the content of which is incorporated in this application by reference.

TECHNICAL FIELD

This invention relates generally to the field of optical fiber sensing systems and, more particularly, to improved systems and methods for accurately sensing fluid migration in and around a wellbore.

BACKGROUND OF THE INVENTION

The migration of fluid (e.g., gases, unwanted liquids, etc.) to the surface from deep gas formations is a problem that can lead to disastrous consequences. Underground gas storage facilities have demonstrated a long history of environmental problems caused by unwanted gas migration. Gas migration is also a concern from abandoned (i.e., plugged) wells that are no longer in use. However, it is the widespread production of natural gas from tight shale beds via the combination of horizontal drilling and hydraulic fracturing (i.e., hydrofracking) that has now brought the issue of gas migration to the national consciousness.

One particular concern is the possibility of natural gas migrating from a deep shale gas producing zone to near surface aquifers, thus contaminating the water and/or collecting in low lying surface areas with dangerous implications. Most experts within the industry agree that the only viable path for natural gas to migrate from deep underground gas reservoirs (e.g., shale beds, gas storage facilities, etc.) to the surface or to shallow underground aquifers is via man-made wellbores. For example, this migration may occur along the outside of the wellbore casing due to degraded or improperly installed cement. Leakage occurring inside the casing is less of a problem
in the shale gas situation as it can be vented and collected at the surface. One potential source of cement degradation occurs during hydrofracking, where high pressure fluid (e.g., in excess of 10,000 psi) is injected into the shale bed to fracture the shale and release the natural gas. Fluid under such high pressure may result in the development of channels along the outside of the wellbore casing through the cement itself, between the cement and the casing, between the cement and the surrounding earth, or some combination thereof.

A conventional technique for detecting wellbore leakage is to temporarily lower an acoustic sensor into the center of a wellbore while listening for signs of leakage. Such a technique is not practical for monitoring a producing well, for example, because it requires suspension of gas or oil production, costly removal of production hardware (e.g., tubing, etc.), installation of a sensor or sensor string, detection and interpretation of data, and removal of the sensor or sensor string. Further, detecting leakage outside of the wellbore casing (i.e., through the various layers of casing/production tubing) using such a technique involves significant challenges.

Thus, a need exists for, and it would be desirable to provide, improved wellbore leak detection systems.

BRIEF SUMMARY OF THE INVENTION

To meet this and other needs, and in view of its purposes, the present invention provides, according to an exemplary embodiment, a leak detection system for a wellbore. The leak detection system includes: (1) at least one sensor configured to be positioned outside of a casing of a wellbore; (2) an interrogation system for sending signals to, and receiving signals from, the at least one sensor; and (3) an optical lead cable disposed between the interrogation system and the at least one sensor.

According to another exemplary embodiment of the present invention, a method of detecting a fluid leak in a wellbore is provided. The method includes the
steps of: (a) transmitting light from an interrogator to at least one sensor positioned outside of a casing of a wellbore; (b) receiving return signals from the at least one sensor at the interrogator; and (c) processing the return signals to determine if there is an indication of a fluid leak from the wellbore casing.

It is to be understood that both the foregoing general description and the following detailed description are exemplary, but are not restrictive, of the invention.

**BRIEF DESCRIPTION OF THE DRAWINGS**

The invention is best understood from the following detailed description when read in connection with the accompanying drawings. It is emphasized that, according to common practice, the various features of the drawings are not to scale. On the contrary, the dimensions of the various features are arbitrarily expanded or reduced for clarity. Included in the drawing are the following figures:

FIG. 1 is a block diagram illustrating a leak detection system installed in relation to a borehole in accordance with an exemplary embodiment of the present invention;

FIG. 2 is a block diagram illustrating a leak detection system, in accordance with an exemplary embodiment of the present invention, using a Michelson-based interferometer;

FIG. 3 is a block diagram illustrating another leak detection system, in accordance with an exemplary embodiment of the present invention, using a hybrid of Time Division Multiplexing (TDM) and Wavelength Division Multiplexing (WDM);

FIG. 4 is a block diagram illustrating yet another leak detection system, namely a TDM-based system, in accordance with an exemplary embodiment of the present invention; and
FIG. 5 is a block diagram illustrating yet another leak detection system, in accordance with an exemplary embodiment of the present invention, using a combination of interferometric interrogation and Rayleigh backscatter interrogation.

**DETAILED DESCRIPTION OF THE INVENTION**

As used in this document, the term “wellbore casing” is intended to refer to any structure that separates a wellbore (e.g., the bore configured to house the fluid during transport) from the surrounding geological structure. Exemplary wellbore casings are formed of cement and steel, and may be layered wall structures. As is understood by those skilled in the art, as a fluid (e.g., natural gas, oil, etc.) travels through the wellbore, the wellbore casing often serves to protect aquifers from fluids migrating from within the wellbore casing to the aquifers.

The present invention relates to systems and methods utilizing a plurality of optical fiber sensors installed outside of a wellbore casing (e.g., embedded within the wellbore casing cement) for the detection of fluid (e.g., liquid, gas, etc.) migration such as a fluid leak through the wellbore casing. The optical fiber sensors may be installed, for example: (1) against the wellbore casing; or (2) in an area between the wellbore casing and the well opening, such as in the wellbore casing cement.

According to various exemplary embodiments of the present invention, leak detection systems are provided which include three major subassemblies: (1) a fiber optic sensor assembly along a cable designed to detect acoustic pressure signals, seismic vibrations, or both, where the sensor assembly may include a plurality of discrete sensors within or along the cable, or one or more continuous sensors comprised mainly of optical fiber within the cable; (2) an interrogation system having a light source for transmitting light (which may be modulated) to the sensor assembly, and electronics to process returning optical signals from the sensor assembly and to translate the returning optical signals into a format (e.g., a digital format) suitable for either recording and/or signal processing; and (3) a signal processing unit designed to differentiate between signals of interest (e.g., leakage) and other ambient noises.
The fiber optic sensor cable, which may consist of long continuous sensors and/or point sensors, would typically be mounted against or adjacent the outside of the wellbore casing, as sections of the casing are being lowered into the well hole. For example, portions of the fiber optic sensor cable may be attached to the sections of the wellbore casing using straps or other appropriate mechanisms. The fiber optic sensor cable may include metal armor, a polymer jacket, or other mechanisms to protect it from damage during installation and subsequent operation. After a portion of the wellbore casing has been inserted into the well hole, the gap between the wellbore casing and the surrounding earth can be filled with cement or another appropriate fill material. Such a mounting scheme tends to improve the signal-to-noise ratio that would be associated with fluid migration along the outside of the wellbore. Further, such a mounting scheme is simple and cost effective compared to conventional downhole sensor arrangements where the temporary fiber optic sensors are installed within the wellbore casing.

A set of surface (i.e., topside) electronics are connected to the fiber optic sensor cable using a lead cable. Using this leak detection system, relatively small acoustic and/or seismic signals can be detected downhole along the length of the fiber optic sensor cable. In order to detect gas migration (e.g., a potential leak), it may be desirable that the producing well be shut down periodically at the surface while monitoring for any signs of leakage/flow. Thus, any indication of flow detected by the downhole sensor array would be an indication of unwanted leakage.

Different types of sensor arrays and interrogation systems may be utilized. For example, the sensor array may include Michelson interferometers (e.g., see FIG. 2), Sagnac interferometers, or Fabry-Perot interferometers (e.g., see FIGS. 3-4), among others. Exemplary interrogators include interferometric interrogators (e.g., TDM interrogators such as shown in FIGS. 3-4) and Rayleigh backscatter interrogators (e.g., see FIG. 5), among others. In another embodiment, once a leak has been detected, the normal surface electronics are switched such that a first interrogator (e.g., an interferometric interrogator) is electronically disabled/deselected, and a second interrogator (e.g., a Rayleigh backscatter
interrogator) is activated to provide a high precision location of the detected leak (e.g., see FIG. 5).

Referring now to the drawings, FIG. 1 illustrates a leak detection system configured to detect fluid leaks in connection with a wellbore 100 formed in earth 104. A well hole is formed in earth 104, and a wellbore casing 102 defines wellbore 100 within the well hole. Casing 102 may be formed from a rigid material such as a metal (e.g., steel), a plastic (e.g., PVC), or other suitable material. Wellbore 100 may be any desired depth, for example, from hundreds to tens of thousands of feet deep, and may be used for the exploration, monitoring, storage and production of fluids such as oil, natural gas, carbon dioxide, and geothermal energy. Although not shown in FIG. 1, a length of “production” tubing (e.g., metal tubing) may be provided within wellbore 100 through which the fluid may be transported to the surface. A material 112 (e.g., a cementation material such as grout) is provided between casing 102 and the well hole defined by earth 104. An above-ground location 124 includes surface electronics 106 for detecting fluid leaks from wellbore 100. The surface electronics 106 include an interrogator 114 (also known as interrogation system 114), a signal processor 116, a display 118, and a communication system 120.

As shown in FIG. 1, a sensor array 110 (e.g., a plurality of fiber optic sensors) is installed in a cable within the well hole but outside of casing 102. In the specific example shown in FIG. 1, sensor array 110 is disposed in cementation material 112 between casing 102 and the well hole defined by earth 104. Although sensor array 110 is shown near casing 102 in FIG. 2, it is understood that sensor array 110 may be provided directly against an outside surface of casing 102 or even within casing 102 if desired.

A lead cable 108 (e.g., a length of fiber optic cable) is provided between interrogator 114 and sensor array 110. Sensor array 110 includes a plurality of sensors (e.g., a plurality of optical fiber sensors). Sensor array 110 may be installed permanently as shown in FIG. 1 (e.g., using cementation material 112) or may be installed temporarily.
As will be appreciated by those skilled in the art, interrogator 114 may be an optical interrogator and include an optical source (e.g., a radiation light source such as a laser) for sending optical signals to sensor array 110, and an optical receiver for receiving return optical signals from sensor array 110. The system illustrated in FIG. 1 detects leaks by converting acoustic/vibration energy received at a sensor within sensor array 110 to an optical signal (i.e., the return optical signals from sensor array 110), and then converting the optical signals to electrical signals (e.g., analog or digital signals representative of the acoustic vibration energy received at the plurality of sensors in sensor array 110) within interrogator 114. The electrical signals are then processed using signal processor 116 (e.g., the signal processor may be used to improve the signal-to-noise ratio of the electrical signals, and to apply classification methods to help an operator distinguish between normal wellbore noise and a leak). For example, the information from signal processor 116 (e.g., the raw electrical signals, the processed electrical signals, etc.) may be presented to an operator using display 118, and/or may be communicated to other locations using communication system 120.

The specific elements (e.g., interrogator 114, sensor array 110, etc.) included in the leak detection system of FIG. 1 may vary considerably. FIGS. 2-5 are various applications of the system of FIG. 1 utilizing specific technologies; however, it is understood that the leak detection system of FIG. 1, and the present invention, are not limited to the exemplary embodiments shown in FIGS. 2-5.

Referring specifically to FIG. 2, a Michelson interferometer-based sensing system for wellbore leak detection is illustrated. The leak detection system of FIG. 2 includes a lead cable 208 providing interconnection between a sensor array 240 and surface electronics 200. In FIG. 2, sensor array 240 only includes a single optical fiber sensor (i.e., a single Michelson interferometer). It should be understood, however, that a plurality of optical fiber sensors may be included in sensor array 240. The Michelson interferometer includes an optical coupler 210 for dividing an optical signal between optical fiber leg 212 and optical fiber leg 216. Optical fiber leg 216 is the sensing leg within a cable along a wellbore. A reflector 218 is provided at a distal
end of sensing optical fiber leg 216. Optical fiber leg 212 is a reference leg. Reference optical fiber leg 212 is typically a fiber having a length similar to the fiber in sensing optical fiber leg 216 (e.g., within about 1m in length), where a reflector 214 is provided at a distal end of reference optical fiber leg 212. Reference optical fiber leg 212 is typically wound (e.g., on a spool) in such a way as to render it insensitive to environmental perturbations (e.g., vibration, temperature, etc.).

The operation of the leak detection system of FIG. 2 is provided below. Surface electronics 200 include an interrogator 220, a signal processor 228, a headphone/loudspeaker 234, a display 236, and a communication system 238. Highly coherent light is provided by a light source 202 (e.g., an optical light source such as a laser) within interrogator 220. The light from light source 202 passes through an optical circulator 204 and is modulated by a phase modulator 230 and a reflector 232 (e.g., with a phase carrier). The phase modulated light passes through an optical circulator 206, and is then transmitted to sensor array 240 via lead cable 208.

Under quiet (e.g., unperturbed) conditions, the light from light source 202 is split into two signals/waves at optical coupler 210, with each of the signals travelling along a respective one of legs 212, 216. Each of the signals is reflected back to optical coupler 210 via a respective one of reflectors 214, 218. The reflected signals/waves recombine coherently at optical coupler 210 to yield an optical intensity signal proportional to the phase difference between the relative phases of the light (from each interferometer leg 212, 216) returning to optical coupler 210. This optical intensity signal is measured at interrogator 220. Without perturbations such as a leak, the reflected light signals return to optical coupler 210 with no relative change in their phase, other than that due to any fixed offset due to the differences in the lengths of legs 212, 216, and as such the optical intensity signal measured at interrogator 220 is constant.

The optical intensity signal is converted to an electrical signal by an optical receiver 222, and is then converted to a digital electrical signal by a digitizer 224 (e.g., an analog-to-digital converter). The electrical signal may be demodulated (or
processed directly at baseband if no carrier was applied to the output of light source 202) at a phase demodulator 226 to provide an electrical output directly proportional to the perturbation in the wellbore as a function of time. Signal processor 228 is then used to provide filtering and other functions to further improve the signal-to-noise ratio and the general quality of the electrical signal. Signal processor 228 may also apply a classification to aid in distinguishing the time-base or frequency spectrum of the detected signal of a leak from normal background noise. The information from signal processor 228 (e.g., the raw electrical signals, the processed electrical signals, etc.) may be audibly or visually provided to an operator using headphone/loudspeaker 234 or display 236, respectively, and/or may be communicated to other locations using communication system 238.

When a disturbance (e.g., a leak) exists in the vicinity of the wellbore (where the wellbore is not shown in FIG. 2 but is indicated as wellbore 100 in FIG. 1), the disturbance causes the optical fiber in sensing leg 216 to be perturbed or to move. This causes a slight instantaneous change in the phase of the optical wave passing along sensing optical fiber leg 216. Because reference optical fiber leg 212 is wound and/or packaged in such a way as to be insensitive to such a disturbance, however, the phase of the optical wave passing along reference optical fiber leg 212 is unperturbed. This causes a slight, instantaneous, change in the phase angle between the two waves (i.e., the two waves reflected back from legs 212, 216) when they return to optical coupler 210. At optical coupler 210, this slight change in the phase angle is converted directly to an intensity change in the light that returns along lead cable 208 to interrogator 220.

Although FIG. 2 is described in connection with a Michelson-based interferometer sensing system, it is understood that different systems may be used. One exemplary variation is the replacement of the Michelson interferometer(s) in the sensing system with linearized Sagnac interferometers, along with associated changes to the surface electronics.
Referring specifically to FIG. 3, a hybrid TDM/WDM-based sensing system for wellbore leak detection is illustrated. The leak detection system of FIG. 3 includes a lead cable 312 providing interconnection between a sensor array 314 and surface electronics 300. Sensor array 314 is provided along a wellbore casing (e.g., as in FIG. 1) and includes an array of at least one fiber optic sensor S1, S2, . . ., S6, etc. Each sensor includes a length of optical fiber bound by a pair of Fiber Bragg Gratings (i.e., FBGs). For example, sensor S1 is bound by FBG 314a and FBG 314b, sensor S2 is bound by FBG 314b and FBG 314c, sensor S3 is bound by FBG 314d and FBG 314e, sensor S4 is bound by FBG 314e and FBG 314f, sensor S5 is bound by FBG 314g and FBG 314h, and sensor S6 is bound by FBG 314h and FBG 314i. As shown in FIG. 3, there are two sensors at each of three different wavelengths (i.e., sensors S1 and S2 at λ1, sensors S3 and S4 at λ2, and sensors S5 and S6 at λ3).

Surface electronics 300 include an interrogator 302 (including a TDM phase demodulator) for providing pulsed interrogation light, and for modulating that light and transmitting it to sensor array 314 via lead cable 312. Interrogator 302 includes multiple narrow linewidth lasers (on the order of 0.1 to 10 kHz full width at half maximum) at different wavelengths, denoted by λ1 to λ3. Lead cable 312 carries light signals (that may be phase modulated) from interrogator 302 to sensor array 314. Likewise, lead cable 312 also carries the return light signals which include the phase modulated light mixed with the additional phase perturbations caused within a series of Fabry-Perot interferometers defined by the FBGs.

As provided above, sensor S1 is bound by FBGs 314a, 314b and sensor S2 is bound by FBGs 314b, 314c. As will be appreciated by those skilled in the art, because the wavelengths of FBGs 314c and 314d are different from one another there is no coherent interference of light reflecting from them that would otherwise create yet another sensor therebetween. Further, FBGs 314c and 314d are very close together (e.g., with a spacing between FBGs 314c and 314d on the order of 1-10 cm). Thus, to interrogator 302, FBGs 314c and 314d appear to be at the same location (i.e., because of the time of flight of light). More specifically, within the TDM phase demodulator included in interrogator 302, sensors S2 and S3 on either side of this pair
of FBGs (i.e., FBGs 314c and 314d) appear to be bound at a common location. The same is true for sensors S4, S5 on either side of FBGs 314f, 314g.

Surface electronics 300 also include a signal processor 304, a headphone/loudspeaker 306, a display 308, and a communication system 310. Each sensor S1, S2, . . . , S6 in sensor array 314 returns a series of pulses to the TDM phase demodulator within interrogator 302 with phase information perturbed by received vibrations stretching or contracting the optical fiber in the respective sensor. Signal processor 304 is used, for example, to apply filtering, fast Fourier transforms, and decimation to the data from interrogator 302. Signal processor 304 may also be used to provide classification functions to distinguish signals arising from fluids leaking along the casing from background noise. A display 308 may be included for visual observation of alarm (leak) conditions. A headphone/loudspeaker 306 (which may be any type of audible device) may also be connected to the output of signal processor 304 for auditory (e.g., manual) classification by a trained operator. Communications may also be provided from a communication system 310, for example, for remote alarm and analysis functions.

Referring specifically to FIG. 4, a TDM (i.e., time division multiplexing)-based sensing system for wellbore leak detection is illustrated. The leak detection system of FIG. 4 includes a lead cable 412 providing interconnection between a sensor array 414 and surface electronics 400. Sensor array 414 is provided along a wellbore casing (e.g., as in FIG. 1) and includes an array of fiber optic sensors S1, S2, . . . , S6, etc. Each sensor includes a length of optical fiber bounded by a pair of Fiber Bragg Gratings (i.e., FBGs). For example, sensor S1 is bound by FBG 414a and FBG 414b, sensor S2 is bound by FBG 414b and FBG 414c, sensor S3 is bound by FBG 414c and FBG 414d, sensor S4 is bound by FBG 414d and FBG 414e, sensor S5 is bound by FBG 414e and FBG 414f, and sensor S6 is bound by FBG 414f and FBG 414g. Each FBG is typically provided at the same length, with a peak reflectivity in the wavelength region of, for example, 1500-1600 nm, and with an exemplary magnitude of 0.1 – 10%. Surface electronics 400 include an interrogator 402 (including a TDM phase demodulator) for providing
pulsed interrogation light, and for modulating that light and transmitting it to sensor array 414 via lead cable 412, and then for demodulating and demultiplexing the phase signals returning from each sensor. Surface electronics 400 also include a signal processor 404, a headphone/loudspeaker 406, a display 408, and a communication system 410. Each sensor S1, S2, . . . , S6 in sensor array 414 returns a series of pulses to the TDM phase demodulator within interrogator 402 with phase information perturbed by received vibrations stretching or contracting the optical fiber in the respective sensor. As will be understood by those skilled in the art, the TDM phase demodulator within interrogator 402 beats these signals against a compensating interferometer within the demodulator of interrogator 402, converts the resulting intensity signal to an electrical signal, demodulates the electrical signal, and demultiplexes the electrical signal into one from each of the sensors. Signal processor 404 is used, for example, to apply filtering, fast Fourier transforms, and decimation to the data from interrogator 402. Signal processor 404 may also be used to provide classification functions to distinguish signals arising from fluids leaking along the casing from background noise. A display 408 may be included for visual observation of alarm (leak) conditions. A headphone/loudspeaker 406 (which may be any type of audible device) may also be connected to the output of signal processor 404 for auditory (e.g., manual) classification by a trained operator. Communications may also be provided from a communication system 410, for example, for remote alarm and analysis functions.

Referring specifically to FIG. 5, a combination-based sensing system (i.e., a combination of interferometric interrogation and Rayleigh backscatter interrogation) for wellbore leak detection is illustrated. The leak detection system of FIG. 5 includes a lead cable 516 providing interconnection between a sensor array 518 and surface electronics 500. Sensor array 518 is provided along a wellbore casing (e.g., as in FIG. 1) and includes an array of fiber optic sensors such as those included in sensor array 414 in FIG. 4 (i.e., sensors S1, S2, . . . , S6, etc. including a length of optical fiber bounded by a pair of FBGs). Typically, during normal sensing operations, an interferometric interrogator 502 (similar to interrogator 402 of FIG. 4) is operated because it has a lower signal-to-noise ratio as compared to a Rayleigh backscatter
interrogator 504. Upon detecting a leak, the leak detection system switches over the interrogation operation to Rayleigh backscatter interrogator 504. Interrogator 504 pulses light signals (e.g., at a different wavelength than the FBG reflection peaks) and then measures the return light signals from sensor array 518 (e.g., which may be a changing intensity or phase information that is beat against a compensating interferometer within interrogator 504) to determine the perturbation (vibration) of the fiber. A signal processor 506 processes (e.g., filters, etc.) the data from interrogator 504 (or interrogator 502 during normal operation). Signal processor 506 may also be used to provide classification functions to distinguish signals arising from fluids leaking along the wellbore casing from background noise. A headphone/loudspeaker 508 (which may be any type of audible device) may also be connected to the output of signal processor 506 for auditory (e.g., manual) classification by a trained operator. A display 510 may be included for visual observation of alarm (leak) conditions. Communications may also be provided from a communication system 512, for example, to provide remote alarm, analysis, and other functions.

Although each of FIGS. 2-5 are illustrated and/or described with a limited number of sensors in the respective sensor array, it is understood that any number of sensors may be included in the sensor array, as desired.

As described above, certain exemplary embodiments of the present invention utilize acoustically sensitive optical fiber (e.g., in the sensors of a sensor array) to sense fluid leaks. The sensors utilizing optical fiber may also desirably include a transducer/accelerometer. Exemplary transducers/accelerometers are shown in PCT International Publication No. WO 2011/050227 entitled “FIBER OPTIC TRANSDUCERS, FIBER OPTIC ACCELEROMETERS AND FIBER OPTIC SENSING SYSTEMS.” For example, an exemplary transducer includes a fixed mandrel, a moveable mandrel, and a spring between the fixed mandrel and the moveable mandrel. The fixed mandrel is rigidly attached to a body of interest, and the moveable mandrel may move with respect to the fixed mandrel. A length of optical fiber is wound around the fixed mandrel and the moveable mandrel. This wound length of optical fiber is optically connected to (or continuous with) the length
of optical fiber included in the relevant sensor of the sensor array. By including such a transducer in the sensor, the optical fiber (including the portion wound around the fixed mandrel and the moveable mandrel) has improved sensitivity. Of course, alternative types of transducers and accelerometers may be utilized within the scope of the present invention.

Although the present invention has been described in connection with certain exemplary elements (e.g., the elements illustrated and described in connection with FIGS. 2-5), it is not limited to those elements. As will be understood by those skilled in the art, certain elements may be omitted, certain elements may be added, and certain elements may be exchanged for different elements. In one specific example, optical circulators 204 and 206 of FIG. 2 may be replaced with a single optical circulator (e.g., a single four-port optical circulator as opposed to two three port optical circulators as shown in FIG. 2).

The present invention may also be implemented as a method of detecting a fluid leak in a wellbore. Such methods may be performed using the configuration of FIG. 1, and may also use any of the more specific configurations of FIGS. 2-5, among other configurations. Prior to detecting a potential fluid leak in a wellbore, one or more sensors (e.g., fiber optic sensors) are positioned outside of a wellbore casing within the well hole. For example, the one or more sensors may be configured as a sensor array such as those described above in connection with any of FIGS. 1-5. The sensor array is connected to surface electronics (including an interrogator) via a lead fiber optic cable. It may be desirable to temporarily suspend extraction of the fluid from the wellbore during at least a portion of the leak detection process such that the leak detection system may be able to more accurately sense ambient noises and/or vibrations caused by a fluid leak.

The method continues by launching optical signals (i.e., light such as laser light) from a light source in the interrogator to the sensor array, for example, to sensors over a distributed length of the wellbore casing. Return optical signals are received by an optical receiver at the interrogator. The return signals are processed
(e.g., using a signal processor) to determine if any noise and/or vibration sensed by the sensor array is normal background noise or an indication of an unwanted fluid flow/migration (e.g., a leak).

The processing of the signals may be accomplished using varying techniques. Therefore, it should be understood that the method steps recited in this document are exemplary in nature. The return signals from the sensor array may initially be converted into phase change and/or light intensity change signals, and these change signals may then be converted into electrical signals (e.g., using a photodiode). The electrical signal output from this conversion is processed such as through demodulation, demultiplexing, amplification, filtering, sampling, and windowing at the interrogator in the surface electronics. A signal processor may then be used to apply a FFT (Fast Fourier Transform), a DFT (Discrete Fourier Transform), or other technique to the processed electrical signal output to yield an instantaneous spectrum. For example, in the case of the application of a FFT, the FFT may be applied to the data over a time frame on the order of 0.25 seconds. Further, multiple contiguous (or overlapping) FFTs may be averaged over a longer period of time (e.g., tens of seconds). In any event, the instantaneous spectrum yielded by the FFT or other process may be compared to spectra stored and related to certain conditions (e.g., normal noise, leak conditions, etc.) in order to detect a potential leak. If such a comparison yields any positive matches (e.g., within a predetermined tolerance), then such a condition may be stored, reported as an alarm, etc. Specifically, the comparison may look for a broadband noise in the 1-10 kHz range that is indicative of a leak (e.g., a hissing) which lasts a relatively long time and is differentiated from known noises such as impulse noises from hydrofracturing, perforation explosions, air gun impulses, etc.

Although illustrated and described above with reference to certain specific embodiments, the present invention is nevertheless not intended to be limited to the details shown. Rather, various modifications may be made in the details within the scope and range of equivalents of the claims and without departing from the spirit of the invention.
What is Claimed:

1. A leak detection system for a wellbore having a casing with an exterior surface, the leak detection system comprising:

   at least one sensor configured to be positioned outside of the casing of the wellbore;

   an interrogation system for sending signals to, and receiving signals from, the at least one sensor; and

   an optical lead cable disposed between the interrogation system and the at least one sensor.

2. The leak detection system of claim 1 wherein the at least one sensor includes a fiber optic cable configured as part of an interferometer.

3. The leak detection system of claim 2 wherein the interferometer is a Michelson interferometer.

4. The leak detection system of claim 2 wherein the interferometer is a Sagnac interferometer.

5. The leak detection system of claim 2 wherein the interferometer is a Fabry-Perot interferometer.

6. The leak detection system of claim 1 wherein the interrogator includes an optical source, an optical receiver, and a digitizer.

7. The leak detection system of claim 1 wherein the at least one sensor includes a fiber optic cable optically divided into a series of sensing zones.

8. The leak detection system of claim 7 wherein the fiber optic cable is optically divided into a series of sensing zones using fiber Bragg gratings written into the fiber optic cable, thereby forming a series of Fabry-Perot interferometers.
9. The leak detection system of claim 1 wherein the at least one sensor includes at least one of an acoustic or a seismic sensor.

10. The leak detection system of claim 1 wherein the at least one sensor includes an optical fiber and an accelerometer, the accelerometer including a fixed mandrel and a moveable mandrel, wherein the optical fiber is wrapped around the fixed mandrel and the moveable mandrel.

11. The leak detection system of claim 1 wherein the at least one sensor is secured to the exterior surface of the casing of the wellbore.

12. The leak detection system of claim 1 wherein the at least one sensor is embedded in a fill material outside of the casing of the wellbore.

13. The leak detection system of claim 1 wherein the interrogator is a Rayleigh backscatter interrogator configured to process scattered intensity return signals from the at least one sensor.

14. The leak detection system of claim 1 wherein the interrogator is a Rayleigh backscatter interrogator configured to process scattered phase return signals from the at least one sensor.

15. A method of detecting a fluid leak in a wellbore, the method comprising the steps of:

   (a) transmitting light from an interrogator to at least one sensor positioned outside of a casing of a wellbore;

   (b) receiving return signals from the at least one sensor at the interrogator; and

   (c) processing the return signals to determine if there is an indication of a fluid leak from the wellbore casing.
16. The method of claim 15 further comprising the step of installing a plurality of optical fiber sensors outside the casing of the wellbore prior to step (a).

17. The method of claim 15 wherein step (c) includes converting return optical signals into electrical signals for processing by a signal processor.

18. The method of claim 17 wherein step (c) further includes generating an instantaneous spectrum of the electrical signals and comparing the instantaneous spectrum against a predetermined spectra related to a leak condition.

19. The method of claim 15 further comprising the step of (d) determining a location of the fluid leak if a determination is made at step (c) that there is a fluid leak.

20. The method of claim 19 wherein step (d) includes determining the location of the fluid leak using a Rayleigh backscatter interrogator.

21. The method of claim 15 wherein the signals received in step (c) have been converted into phase change and light intensity change signals.

22. The method of claim 21 wherein step (c) includes demodulating and demultiplexing the phase change and light intensity change signals.

23. The method of claim 15 further comprising the step of installing the at least one sensor against an exterior surface of the casing of the wellbore before step (a).

24. The method of claim 15 wherein the at least one sensor includes a plurality of sensors.

25. The method of claim 24 wherein the at least one sensor includes a fiber optic cable configured as part of an interferometer.

26. The method of claim 25 wherein the interferometer is a Michelson interferometer.
27. The method of claim 25 wherein the interferometer is a Sagnac interferometer.

28. The method of claim 25 wherein the interferometer is a Fabry-Perot interferometer.